92-01210/

AN EXPERIMENTAL STUDY OF THE GAS-NUCLEATION PROCESS DURING THE PRIMARY-PRODUCTION PHASE IN HEAVY-OIL RESERVOIRS UNDER SOLUTION-GAS DRIVE

[PART OF ENERGY, MINES AND RESOURCES COST SHARED ENERGY CONVERSION PROGRAM AND PART OF THE PROGRAM OF THE FEDERAL PANEL ON ENERGY R&D (PERD)]

FINAL REPORT

by:

H.K. Sarma, B.B. Maini, F. Nicola and J. Goldman

Petroleum Recovery Institute
3512 - 33rd Street N.W.
Calgary, Alberta T2L 2A6

Work on the project was conducted under the auspices of the Canada Centre for Mineral and Energy Technology, Energy, Mines and Resources Canada.

MICROMEDIA

DSS FILE No. 006SQ.23440-9-9265
DSS CONTRACT SERIAL No. 23440-9-9265/01-SQ
CANMET SCIENTIFIC AUTHORITY: Dr. A.E. George

60 pp

May 30, 1991

EXECUTIVE SUMMARY

The objective of the experimental study presented in this report was to investigate the role of gas nucleation in the primary production of heavy oils under solution-gas drive. We were particularly interested in determining whether or not the nucleation of gas bubbles improves the mobility of heavy oils in a porous medium. A secondary objective was to study the flow behaviour of foamy oils.

A novel apparatus was designed and assembled to carry out simulated solution gas drive experiments in a 200 cm long sandpack. Recombined oil was injected into one end of the sand pack at constant pressure (equal to the saturation pressure) and was produced from the other end at constant back pressure. The oil production rate and pressure profile within the sand pack were measured at various values of pressure drawdown. Experiments were conducted using two heavy oils: Lloydminster and Lindbergh oils and a refined oil, Bright-150. The effect of gravitational forces was evaluated by conducting the flow experiments in both horizontal and vertical directions.

The experimental data show that the nucleation of gas bubbles under the solution-gas drive did not enhance oil mobility. However, the oil production behaviour was not the same as one would expect from a typical conventional oil reservoir under the solution-gas drive. The most striking difference was in the flow behaviour of the gas phase. Even at the highest pressure drawdown it appeared to flow mostly as a dispersed phase. Only for occasional brief periods the gas was observed to flow as a continuous phase. The plot of pressure drop in the segment near the production end against time displayed a cyclic behaviour at high drawdown. A relatively long period of gradual pressure increase was followed by short period of rapid pressure decline and this pattern was repetitive. It is suggested that the oil/gas mixture was flowing in form of an oil continuous foam during the period of increasing differential pressure. After reaching a critical pressure gradient, the foam collapsed to form a continuous gas phase which caused a reduction in the differential pressure. However, the flow of continuous gas phase was soon cut off by oil moving into the depressurized pores and the gradual buildup of the differential pressure started again.

The free gas saturation was measured at end of the highest drawdown experiment by injecting oil into the core with outlet end closed and was found to be around 15% of the pore volume. However, judging from the pressure profile, most of this gas was in the segment nearest to the outlet. Therefore the free gas saturation near the outlet end was probably close to 40%.

Based of the findings of this study, it appears likely that the primary production from the heavy oil reservoirs under the solution-gas drive can recover a much higher fraction of the original oil in place. It was noted that characteristics of the oil and the porous medium appeared to have a significant impact on the gas nucleation process. Therefore the impact of foamy oil behaviour on oil production will not be the same in all reservoirs. It is recommended that further investigations be undertaken to define the effects of various parameter on flow behaviour of foamy oils.

SOMMAIRE EXECUTIF

Cette étude expérimentale avait pour objectif d'investiguer le rôle que joue la nucléation du gaz lors de la production primaire d'huile lourde par déplacement solution-gas. Nous étions particulièrement intéressés de connaître si la nucléation des bulles de gaz améliorait ou pas la mobilité des huiles lourdes en milieu poreux. Un objectif secondaire était d'étudier le comportement de l'écoulement d'huiles mousseuses.

Un appareil tout nouveau fut conçu et assemblé de façon a pouvoir simuler les déplacements de solution-gas en milieu poreux de 200 cm de long. Pour ce faire, on injecta de l'huile reconstitué a une extrémité du milieu poreux et à pression constante, et l'on produisit l'huile à l'autre extrémité avec une pression de retenue constante. Le taux de production ainsi que la pression différentielle du milieu poreux, furent mesurés pour des valeurs variée de pression de retenue. Pour ce faire, on utilisa deux types d'huile lourde: Lloyminster et Lindbergh, et une huile raffinée, Bright 150. L'effet des forces gravitationnelles fut évalué en conduisant les testes d'écoulement horizontal et vertical.

Les résultats obtenues démontrèrent que la nucléation des bulles de gaz, en déplacement solution-gas, n'ont pas d'effet positif sur la mobilité de l'huile. Cependant, le comportement de la production d'huile ne se conforma pas à ce que l'on attend d'un déplacement typique solution-gas en réservoir dit conventionnel. Une différence marquée fut observée dans le comportement de la phase gazeuse. Même à la plus haute pression de retenue, la phase gazeuse s'écoulait sous forme dispersée. La courbe de la phase gazeuse sous forme continue fut observée sur de très courtes périodes de temps. La pression différentielle, pour la section finale démontra un comportement cyclique lors de haute pression de retenue. On observa une augmentation graduelle de la pression suivit par des réductions rapides de pression. Ce phénomène était répétitif. Comme explication, il fut suggéré que le mélange huile/gaz s'écoulait sous forme d'huile mousseuse durant la période d'augmentation de la pression différentielle, et ce après avoir atteint un gradient de pression critique. La mousse perdit sa consistance pour ainsi former une phase continue ce qui causa une réduction de la pression différentielle. Cependant, l'écoulement continu de la phase gazeuse fut rapidement interrompue par l'huile envahissant les pores dépressurisées, et ainsi l'accroissement graduel de la pression différentielle recommenca un autre cycle.

La saturation de gaz libre fut obtenue à la fin du teste qui avait la pression de retenue la plus haute, et ce en injectant de l'huile dans le milieu poreux avec l'extrémité du milieu poreux fermée. Ainsi, on a déterminé une saturation d'environ 15 % du volume poreux. D'après le profile de la pression, on estima que la majorité du gaz se situait dans la section tout près de la sortie du milieu poreux. Ainsi, la saturation de gaz libre près de la sortie était probablement assez près de 40 %.

Selon les résultats de cette étude, il apparait que la production primaire des réservoirs d'huiles lourdes, sous déplacement solution-gas, pourrait récupérer une fraction

plus importante de l'huile originalement en place. De plus, on observa que les caractéristiques de l'huile et du milieu poreux ont un impact majeur la nucléation du système gazeux. Également, l'impact du comportement de l'huile mousseuse sur la production d'huile ne sera pas le même pour tous les réservoirs. Il est recommandé que des investigations plus approfondies soient menées pour que l'on puisse définir les effets de paramètres variés sur le comportement des huiles mousseuses.

TABLE OF CONTENTS

1.0 INTRODUCTION 1

2.0 LITERATURE REVIEW 2

3.0 OBJECTIVE 7

4.0 EXPERIMENTAL APPARATUS AND MATERIALS 7
- 4.1 Apparatus 7
- 4.2 Materials 8
  - 4.2.1 Fluids 8
    - 4.2.1.1 Preparation of Recombined (Live) Oil 9
  - 4.2.2 Rock Matrix 10

5.0 FLOW EXPERIMENTS 10
- 5.1 Homogeneity Test 10
- 5.2 Scheduling of Flow Experiments 11

6.0 EXPERIMENTAL RESULTS AND ANALYSES 11
- 6.1 Oil Production Rate 12
  - 6.1.1 Effect of Gravity on the Oil Production Rate 13
- 6.2 Pressure Distributions in the Sandpack 14
  - 6.2.1 Pressure Distribution in Individual Segments 14
- 6.3 Effect of Rock Matrices 17
- 6.4 Effect of Oil Characteristics 17

7.0 SUMMARY AND CONCLUSIONS 18

8.0 RECOMMENDATIONS 19

ACKNOWLEDGEMENTS 20

REFERENCES 21

LIST OF TABLES

Table 1: Properties of Porous Media 23

Table 2: Properties Reservoir Oil Samples 23

Table 3: Live Oil Conditions at 21°C 23

LIST OF FIGURES

Figure 1: Schematic Diagram of the Experimental Apparatus

Figure 2: Oil-Gas Recombination Equipment

Figure 3: Solution Gas-Oil-Ratio as a Function of the Equilibrium Pressure as Measured in a Differential Liberation Test

Figure 4: Homogeneity Test of Porous Medium

Figure 5: Effect of Pressure Drawdown on the Oil Production Rate for Gas-Saturated Refined Bright-150 Oil

Figure 6: Effect of Pressure Drawdown on the Oil Production Rate for Gas-Saturated Lloydminster Heavy Oil

Figure 7: Effect of Pressure Drawdown on the Oil Production Rate for Gas-Saturated Lindbergh Heavy Oil

Figure 8: Pressure Distribution in the Porous Medium (Bright-150 Oil, Horizontal Flow)

Figure 9: Pressure Distribution in the Porous Medium (Bright-150 Oil, Vertical Flow)

Figure 10: Pressure Distribution in the Porous Medium (Lloydminster Heavy Oil, Horizontal Flow)

Figure 11: Pressure Distribution in the Porous Medium (Lloydminster Heavy Oil, Vertical Flow)

Figure 12: Pressure Distribution in the Porous Medium (Lindbergh Heavy Oil, Horizontal Flow)

Figure 13: Pressure Distribution in the Porous Medium (Lindbergh Heavy Oil, Vertical Flow)

Figure 14: Comparison of Vertical and Horizontal Pressure Distributions for Bright-150 Oil

Figure 15: Comparison of Vertical and Horizontal Pressure Distributions for Lloydminster Heavy Oil

Figure 16: Comparison of Vertical and Horizontal Pressure Distributions for Lindbergh Heavy Oil

Figure 17: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Bright-150 Oil; Horizontal Flow; Total Drawdown Pressure: 1.0MPa)

Figure 18: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Bright-150 Oil; Horizontal Flow; Total Drawdown Pressure: 3.4MPa)

Figure 19: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Bright-150 Oil; Vertical Flow; Total Drawdown Pressure: 0.35MPa)

Figure 20: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Bright-150 Oil; Vertical Flow; Total Drawdown Pressure: 3.8MPa)

Figure 21: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lloydminster Oil; Horizontal Flow; Total Drawdown Pressure: 0.7MPa)

Figure 22: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lloydminster Oil; Horizontal Flow; Total Drawdown Pressure: 4.8MPa)

Figure 23: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lloydminster Oil; Vertical Flow; Total Drawdown Pressure: 0.7MPa)

Figure 24: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lloydminster Oil; Vertical Flow; Total Drawdown Pressure: 4.2MPa)

Figure 25: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lindbergh Oil; Horizontal Flow; Total Drawdown Pressure: 1.0MPa)

Figure 26: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lindbergh Oil; Horizontal Flow; Total Drawdown Pressure: 3.4MPa)

Figure 27: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lindbergh Oil; Vertical Flow; Total Drawdown Pressure: 0.3MPa)

Figure 28: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time (Lindbergh Oil; Vertical Flow; Total Drawdown Pressure: 4.8MPa)

Figure 29: Effect of the Type of Rock Matrix on the Oil Production Rate (Gas-Saturated Lloydminster Heavy Oil; Horizontal Flow)

Figure 30: Effect of Oil Characteristics on the Oil Production Rate (Horizontal Flow)

1.0 INTRODUCTION

The principal energy in a solution-gas drive reservoir is supplied by the release of solution gas from the oil, and by the expansion of the oil and its originally dissolved gas as the reservoir pressure drops. Because this phenomenon of release and expansion of the solution gas is the primary source of energy, a much faster rate of pressure depletion is often encountered in a solution-gas drive reservoir than in water-drive or gas-cap drive reservoirs (Amyx et al., 1960). The evolution of a free gas phase implies a reduction in the local oil saturation and concomitant reduction in the oil relative permeability. Thus, conventionally, it is expected that the evolution of dissolved gas would hinder the flow of oil in the reservoir. However, laboratory studies and production data from some heavy oil reservoirs suggest that the solution-gas drive in heavy oil reservoirs is much more complex. It has been suggested that in some cases, the release of solution gas, in fact, enhances the oil mobility. What effect -- positive or negative -- the solution-gas drive mechanism will have on the oil production will depend on reservoir conditions and the manner in which the nucleated gas bubbles behave, i.e. the size distribution and the spatial distribution of gas bubbles.

In particular, the coalescence behaviour of bubbles is very important. If the bubbles coalesce readily, a continuous gas phase is formed early and leads to rapid depletion of the reservoir pressure. On the other hand, if the bubbles do not coalesce, instead of a continuous gas phase being formed, a foam in which the oil is the continuous phase is eventually formed. Such foam formation can be beneficial in two ways: (1) it retards the flow of gas and thereby prevents rapid depletion of the reservoir energy; and (2) it traps a

large volume of the gas within the reservoir which increases the fraction of oil that can be recovered under primary.

Several heavy-oil reservoirs in Alberta under the solution-gas drive mechanism, such as Lindbergh and Lloydminster, show "foamy oil" behaviour in wellhead samples, i.e. the produced oil forms an oil continuous foam. Field production data from these reservoirs appear to suggest that production mechanisms are rather complex, and may be quite different from those expected from the conventional solution-gas drive reservoirs. The productivity of some wells is much more than what can be explained by application of the conventional flow equations in radial geometry. One of the suggested causes of this anomalous behaviour is the effect of nucleation of a very large number of gas micro-bubbles. However, no experimental study showing the mobility enhancing role of nucleated gas bubbles has been reported in the literature. Therefore, there is a need to further investigate the role of gas nucleation in primary production from heavy-oil reservoirs under solution-gas drive. Such studies can provide improved strategies for the development and exploitation of the heavy-oil reservoirs under the solution-gas drive.

2.0 LITERATURE REVIEW

When the pressure in a solution-gas drive reservoir drops below its bubble point pressure, a free gas phase forms within the pore space (Dake, 1978). This gas phase then competes with the oil phase for the available flow channels. Initially gas exists in the form of discontinuous and segregated bubbles dispersed in the oil. These bubbles may not flow but may still reduce the relative permeability to the oil phase. However, as the gas

saturation increases above a certain critical value, the gas begins to flow as a continuous phase and the producing gas-oil-ratio begins to rise rapidly. When that happens, the reservoir pressure depletes rapidly. Thus, the recovery factor of solution gas drive reservoirs is inversely related to the producing gas-oil-ratio. In other words, in a solution-gas drive reservoir, as much of the solution-gas as possible should be retained in the reservoir to maximize oil production. In practice, however, little can be done to prevent the liberation of free gas other than taking advantages of some of the rarely available formation features, such as high structural dip, favourable up-dip permeability, thicker pay zone. Also where possible, perforating towards the bottom of the pay zone may reduce the liberation of gas to some extent.

Several studies and field-production data obtained from several solution-gas drive reservoirs appear to contradict this conventional view of the solution-gas drive mechanism (Stewart et al., 1954; Chatenever et al., 1959; Smith, 1986; Danesh et al., 1987). Recognizing the complex behaviour of the solution-gas drive mechanism, Chatenever et al. suggest that although the process of gas nucleation in a solution-gas drive reservoir itself contributes very little to the overall volume of the oil produced, it can, and does, have a significant indirect effect on the oil recovery. The gas bubbles formed due to the nucleation process often reverse their roles under changing reservoir conditions. When the gas is still in the form of discontinuous and dispersed gas bubbles, the released gas has a positive effect on oil production. Once the discontinuous gas bubbles coalesce to form a continuous phase, the gas has a negative effect of the oil production and a rapid depletion of the reservoir pressure occurs.

Based on field production data from the Lloydminster heavy-oil reservoirs in Alberta which are under solution-gas drive, Smith (1986) suggested that the production behaviour from these reservoirs was contrary to what one would normally expect from a solution-gas drive process. Smith's hypothesis is that in these highly viscous oil reservoirs, the fluids are flowing as a mixture of oil and gas bubbles with small relative phase velocities. Therefore, he considered the flow to be a different form of two-phase flow with dispersed tiny gas bubbles moving with the oil. He suggested that, in the Lloydminster reservoir, the gas bubbles continue to grow in size with the increase in the pressure drawdown, which eventually alters the nature of the flow to the more familiar two-phase situation. According to Smith, gas micro-bubbles so formed by the process of gas nucleation appear to enhance the oil production from these reservoirs significantly, and this enhancement in the production is attributed to the increase in the oil mobility brought about by a reduction in the apparent oil viscosity due to the presence of gas micro-bubbles.

It is also possible that the gas-oil mixture behaves in a foam-like manner. Foams are effective in reducing the mobility of the gas phase at capillary pressures higher than a critical value (Khatib et al., 1986). Because the capillary pressure will increase with the increasing gas saturation, the foam formation will prolong the positive role of the gas bubbles by delaying the formation of a continuous gas phase. However, the foam formation is also likely to reduce the oil mobility. It seems evident that the population, i.e. the number of gas bubbles, and the manner in which they are dispersed in the oil determine what role the gas bubbles play in solution gas drive.

Also important are the other formation factors such as: pore size, structure and their distribution (Yortos and Parlar, 1989). Several authors have reported that the population and distribution of gas bubbles were intricately linked with reservoir and rock-matrix characteristics, such as: pore-throat size, and the presence of clays (Kortekaas and Van Poelgeest, 1989, Danesh et. al., 1987). The presence of connate water saturation can also affect the equilibrium between the hydrocarbon phases significantly and delay the formation of a vapour phase (Danesh et al., 1987).

Forest (1982) conducted a general analysis of the equilibrium and stability of a gas-vapour nucleus inside a surface cavity, and showed that the nucleation or the spontaneous growth of a pre-existing nucleus occurred when the radius of curvature reached a minimum value due to an increase in the gaseous volume. This, according to Forest, implies that the liquid-gas interface must be hemispheric

Hunt and Berry (1956) suggested that evolution of gas bubbles under the solution-drive mechanism was a complex process that involved both pressure depletion and diffusion effects. According to them, at the initial stage of bubble formation, the dissolved gas begins to diffuse out of the over-saturated oil into the newly formed gas bubbles. Since there are so few gas bubbles at the initial stage, diffusion paths are very long. That is, in the initial stage of depletion, diffusion plays a less prominent role, and this results in a rapid increase in the number of gas bubbles. When that happens, paths of diffusion become shorter and shorter making diffusion effects more significant at the later stages. Plesset and Prosperetti (1977), too, recognized that the mass-diffusion processes across the bubble-liquid interface

played a very significant role in that they might ultimately determine the presence or absence of bubbles in a liquid.

From the foregoing discussions, it is evident that the production mechanisms from a reservoir under the solution-gas drive have not been fully studied and understood. The process is even more complicated in the case of heavy-oil reservoirs under solution-gas drive because of the presence of asphaltenes, waxes and other polar materials. It is widely believed that the abundance of asphaltenes in heavy oils may provides favourable nucleation sites for these gas bubbles to form and hinders their coalescence. Works of Ward et. al. (1983) and Ward and Levart (1984) also confirm that tiny gas bubbles in the range of 2-5 microns are stable when dispersed in asphaltenes. Because these bubbles are stable, they grow not by coalescence but by the process of pressure depletion.

According to Danesh et. al. (1989), if the gas is not in equilibrium with the reservoir oil, transfer between phases can take place, which, in turn, may change the composition and properties of individual phases. This may induce flocculation of high molecular weight materials, such as asphaltenes, and plug the pores. Also, because asphaltenes are mainly polycyclic aromatic, they can be readily adsorbed on most mineral surfaces (Yen, 1972). Asphaltenes are stabilized in crude by the peptisation action of lower molecular weight resins (Sachanen, 1945). If the gas phase contributes to the change in the composition of oil or if resins are adsorbed on the rock surface, asphaltene deposition may occur. As asphaltenes are charged particles, they may also precipitate as a result of streaming potential generated by the flow of oil through porous media (Leontaritis and Mansoori, 1987).

3.0 OBJECTIVE

The main objective of this study was to develop an understanding of the gas nucleation mechanism during the primary-phase production of heavy oil reservoirs under solution-gas drive by studying its effect on the oil production. In order to meet this objective, the following specific tasks were undertaken:

1. Develop an experimental apparatus capable of simulating the key aspects of solution gas drive.
2. Study the effect of gas nucleation on the oil mobility and determine whether or not the nucleation of gas bubbles increases oil mobility.
3. Study the effect of the pressure drawdown and oil characteristics on the flow of heavy oils under solution gas drive conditions.

4.0 EXPERIMENTAL APPARATUS AND MATERIALS

4.1 Apparatus

The schematic diagram of the experimental apparatus is shown in Figure 1. A two metre long coreholder with six intermediate pressure taps was used. The use of these pressure taps (spaced 33 centimetres apart from one another) facilitated the dynamic monitoring of the pressure distribution during the flow. The dimensions of the coreholder and the properties of the porous medium are listed in Table 1.

The coreholder was placed on a robust steel stand which could be pivoted at any desired angle. Recombined oil (also referred to as "live" oil) was prepared by saturating the oil with methane gas in the recombination equipment connected to the inlet end of the

coreholder. A detailed schematic layout of the recombination equipment is provided in Figure 2.

Because of higher viscosity and a high asphaltene content, frequent problems of plugging were encountered at the inlet end during the flow experiments with the Lindbergh heavy oil. To circumvent such problems of plugging, a filter was placed between the recombination unit and the injection end of the core.

Produced fluids were collected into a graduated cylinder placed on an electronic balance for estimation of the oil production rate.

An automated data acquisition system was employed for reliable and dynamic recording of the oil production rate and the differential pressures in each segment during the flow experiment.

4.2 Materials

4.2.1 Fluids

Flow experiments were conducted using two heavy oils: Lloydminster heavy oil supplied by Mobil Oil Canada and Lindbergh heavy oil supplied by PanCanadian Petroleum Limited. Results of flow experiments with these two heavy oils were compared with a set of base case experiments using a refined oil -- Bright-150 -- supplied by Sunoco of New York. Relevant properties of these oils are presented in Table 2. It is to be noted that the properties listed in Table 2 are those of the "dead" oil; that is, the oil without any dissolved gas.

The data reported in Table 2 were measured in our laboratory. Of the three oils used, Bright-150 was the least viscous (2067 mPa.s), while the Lindbergh oil was the most viscous (10,500 mPa.s). The asphaltene contents which were estimated for the Lloydminster and Lindbergh oils by precipitation with pentane suggested that the Lindbergh heavy oil contained about one and half times higher asphaltene than the Lloydminster heavy oil.

4.2.1.1 Preparation of Recombined (Live) Oil

Prior to the start of flow experiments, each oil sample was cleaned of its suspended materials to ensure ease of pumping and to avoid plugging problem in the manifolds, valves and within the porous medium. The recombined oil was then prepared in the recombination equipment (see Figure 2) under a pressure of 4.83 MPa by saturating it with CH_4. During the process of recombination, the solution gas-oil-ratio (SGOR) was monitored periodically and once a constant SGOR was established, the oil was considered to be fully saturated. This process of recombination of the oil with methane gas usually took about 5-6 days of continuous mixing. Properties of recombined oils are reported in Table 3. Note that the live-oil viscosities were calculated on the basis of the average oil production rate using the Darcy equation.

Solution Gas-Oil-Ratio: Live-oil samples of the Lloydminster and Lindbergh oils were collected in pressure bombs and differential liberation tests were carried out to estimate the solution gas-oil-ratios at several equilibrium pressure. The estimated values of SGOR were plotted as a function of the equilibrium pressure and presented in Figure 3. Note that at

equilibrium pressures below 1.5MPa, the Lindbergh oil data were scattered, and therefore, may not be reliable. Two "eye-ball" correlations were drawn for the two oils and shown in Figure 3.

These correlations suggest that the SGOR-pressure relationship was logarithmic; and between the two oils, the Lindbergh oil appeared to have marginally higher SGOR for the intermediate equilibrium pressures.

4.2.2 Rock Matrix

In this study, two rock matrices were used: glass beads and Ottawa silica sand. The porosity and absolute permeability to the water were determined prior to the start of flow experiments (see Table 1), and the core was then resaturated with "live oil" by displacing the water. During the resaturation process almost 98% of the water was displaced. Because of such low S_{wi} (<2%), the effect of the S_{wi} was considered negligible in this study.

5.0 FLOW EXPERIMENTS

5.1 Homogeneity Test

To ensure the homogeneity of the porous medium, a test was conducted by flowing the refined Bright-150 oil through the porous medium at an equilibrium pressure higher than the saturation pressure of 4.83 MPa. This was accomplished by maintaining the inlet-end pressure at 5.18 MPa, which was 0.35 MPa higher than the saturation pressure, and by maintaining the outlet-end pressure at the saturation pressure.

Since the pressure in the porous medium was above the bubble point pressure, it was assumed that no gas would evolve from the oil during the flow, and if the porous medium were homogeneous, the pressure drop in each segments of the core should almost be equal.

Presented in Figure 4 are the plots of pressure drops in each of the six segments of porous medium for both the horizontal and vertical flows. As evident from this figure, almost equal pressure drop was obtained along the length of the porous medium for both horizontal and vertical flows. This confirmed that the porous medium used in this study was homogeneous.

5.2 Scheduling of Flow Experiments

Flow experiments were carried out in both horizontal and vertical directions, and, for all flow experiments, the pressure at the inlet-end was maintained at the saturation pressure of 4.83 MPa, while at the outlet end it was reduced in steps of about 0.34 MPa by using a back-pressure regulator (BPR). Therefore, for a particular oil, 10-12 flow experiments were conducted in each direction of flow. End-point average gas saturations were estimated after the flow test at highest pressure drawdown and are presented in Table 3.

6.0 EXPERIMENTAL RESULTS AND ANALYSES

During each flow experiment, the oil production and pressure drop in each segment of the porous medium were monitored and recorded as functions of time to ascertain whether the steady-state flow had been established, and to analyze the flow mechanisms in the porous medium . A constant slope in the cumulative-oil-production versus time plot and a constant

pressure gradient in all segments over several hours (2-3 hours) were considered a positive indication of the steady-state flow. Once such steady-state was attained for a particular pressure drawdown, the BPR was reset for the next higher pressure drawdown. In this way, flow experiments were carried out at progressively higher pressure drawdown.

Because the gas nucleation process was initiated by applying progressively higher pressure drawdown in the core, both oil production and pressure data were analyzed as functions of the pressure drawdown.

6.1 Oil Production Rate

Effects of the pressure drawdown on the oil production rate are illustrated in Figures 5, 6 and 7 for the refined Bright-150 oil, Lloydminster and lindbergh oils, respectively. In these figures, data from the vertical flow experiments are represented by the solid triangle, while those from the horizontal flow experiments by the solid circle.

In all three oils, it was evident that initially the oil production rate was linearly increasing with the increasing pressure drawdown across the porous medium. At such drawdown pressures, it was envisaged that the dissolved gas was still in solution with the oil, and therefore, the oil was flowing as a single-phase fluid.

But as the pressure drawdown was increased beyond a certain pressure (1.75 MPa for Bright-150, 1.4 MPa for Lloydminster and Lindbergh oils), it was observed that the increase in the production rate was no longer linear and the rate of increase in the production rate started to decline; in other words, the oil production rate was no longer able to keep pace with the increased pressure drawdown. This behaviour is caused by the evolution of

dissolved gas at higher pressure drawdown which results in two phase flow within the porous medium. And now that the oil phase had to share the pore space with the gas the saturation of the oil and its relative permeability decreased. Another interesting observation was made by simultaneously analyzing the pressure drop profiles and the cumulative oil production trend. The gas bubbles formed at the higher pressure drawdown did not necessarily flow to the production instantly, but rather remained trapped within the porous medium until some critical gas saturation was attained. This behaviour will be discussed in more detail in a subsequent section.

6.1.1 Effect of Gravity on the Oil Production Rate

It appeared that the direction of flow had little impact on the oil production rates, particularly at lower pressure drawdown. For Bright-150 and Lloydminster oils, the vertical flow yielded slightly lower oil production rate than the horizontal flow at a given pressure drawdown. However, reverse seemed to be the case for the Lindbergh heavy oil. For the Lindbergh oil, the vertical flow consistently yielded slightly higher oil production rate than the horizontal flow for drawdown pressures higher than 1 MPa. Since a new batch of recombined oil was used in the vertical flow experiments, it is likely that minor differences in the SGOR between the two batches were responsible for this behaviour. Therefore, within the experimental error, the differences between the horizontal and vertical (upward) production rates are considered insignificant.

6.2 Pressure Distributions in the Sandpack

Profiles showing the pressure distribution in each flow experiments are presented in Figures 8-13 for the three oils studied. Moreover, comparisons of few selected pressure profiles obtained in the vertical and horizontal flow directions are also provided in Figures 14-15 for these oils.

Note that each pressure profile in Figures 8-13 represents the pressure distribution in the porous medium at a particular pressure drawdown when the steady-state flow was attained.

A general trend among these pressure profiles is obvious. The pressure distribution in the porous medium remains linear when the drawdown pressure is below a certain pressure: 1.75 MPa for Bright-150, 1.4 MPa for Lloydminster and Lindbergh oils, and beyond such drawdown pressures, the pressure distribution started becoming non-linear. This trend is consistent with the oil production rate behaviour discussed earlier.

6.2.1 Pressure Distribution in Individual Segments

As progressively higher pressure drawdown was applied, the non-linearity of the pressure profile became more severe suggesting that more and more gas was being liberated and was hindering the flow of oil. The oil-gas mixture being produced from the core was mostly in the form of an oil continuous foam. However, occasionally, a slug of gas was also produced. These happenings and the corresponding mechanisms within the porous medium can be better illustrated with the help of Figures 17-28 which show the differential pressure in segments and the cumulative oil production as functions of time. For each oil, two such

figures are presented for two flow directions; for example, Figure 17 depicts the segment differential pressure and cumulative oil production for Bright-150 oil in the horizontal direction at the pressure drawdown of 1 MPa when the pressure distribution profiles was still linear (cf. Figure 8). Note that Segment 1 was the first segment at the inlet end while Segment 6 was the last segment at the outlet end. Note also that the time in this figure is not the absolute time, but rather an interval chosen arbitrarily for our discussion. Figure 18 depicts similar data but at a much higher pressure drawdown of 3.4 MPa. At this pressure drawdown, the pressure distribution profile was non-linear (cf. Figure 8).

Since all three oils exhibited similar behaviour with respect to the segmental pressure-drop, Figures 17 and 18 for the horizontal flow of the Bright-150 oil are being chosen -- for the sake of convenience -- to provide a general discussion.

A comparison of the pressure drop patterns presented in Figure 17 and 18 demonstrates that the drawdown pressure significantly influenced how the pressure in each individual segment were distributed and balanced under different drawdown pressures. For example, at the pressure drawdown of 1 MPa, the segmental pressure-drop remained constant, and this was accompanied by a steady oil-production rate as implied by the corresponding cumulative oil production curve.

At the higher pressure drawdown of 3.4 MPa, a repetitive cyclic pattern became evident in the segmental pressure drop. It appears that this also had an impact on the oil production rate as manifested by the mild undulation in the cumulative oil recovery curve. Moreover, as the profiles of the segmental pressure-drop indicated, the maximum pressure drop occurred in the last segment, i.e. Segment 6.

The pressure-drop profile for Segment 6 suggests that with continued accumulation of gas in this segment, the pressure drop continued to increase until the gas saturation reached some critical value. When that happened, the trapped gas was produced at the outlet-end in sudden bursts. This was simultaneously accompanied by a sharp and immediate decrease in the pressure drop in Segment 6 and a lower oil production rate which was manifested by the mild undulation in the cumulative oil production curve. But this free flow of the gas was soon arrested and the next cycle of increasing pressure drop in this segment started.

The core average gas saturation at the end of the high drawdown experiments with the Lloydminster and the Lindbergh heavy oils was fairly high (see Table 3). Since, the local pressure was lowest in the last segment, it is likely that this segment may have contained a large part of this gas saturation. The pressure profiles presented in Figures 8-13, too, suggest that this should be the case. For example, during the horizontal flow for the Lloydminster oil (see Figure 10), the profile at the maximum pressure drawdown indicated the linearity in the first three segments and non-linearity for the last three segments. This suggests that the gas was evolved primarily from the last three segments.

However, even among these last three segments, the quantities of the evolved gas were different from one another. This was inferred from the progressive increase in the pressure-drop recorded for these segments. For example, a pressure drop of 0.62 MPa was recorded in Segment 4, while in Segments 5 and 6, they were 0.99 MPa and 1.58 MPa, respectively. This suggested that the pressure drop in the last segment (Segment 6) itself was almost equal to the total pressure drop in Segments 4 and 5. And because the magnitude of

the pressure drop is a measure of the evolved gas saturation, it can be argued -- intuitively -- that the last segment alone could have contained about half of the total gas saturation in the porous medium. This would imply that the gas saturation was around 40% in the last section.

6.3 Effect of Rock Matrices

As indicated in Table 2, flow experiments were carried out at the horizontal position for Lloydminster heavy oil using two rock matrices -- glass beads (k=18.4 d) and silica sand (k=3.35 d) -- to study the effect of the matrix (or permeability) on the gas nucleation process. Although the permeabilities of these two rock matrices were significantly different, the general trends in the behaviour of the oil production rate and the pressure distributions were similar for both matrices.

Presented in Figure 29 is a comparison of the oil production rates obtained using these two matrices. As evident in this figure, in both cases there was a linear relationship between the pressure drawdown and oil production rate up to a certain pressure drawdown beyond which the increase in oil production rate started to decline. It is evident that the higher oil production attained in the porous medium of glass beads was primarily due to its higher absolute permeability.

6.4 Effect of Oil Characteristics

As shown in Table 2, the viscosity of the field sample of the Lindbergh heavy oil was about 20% higher than the viscosity of the Lloydminster heavy oil. The laboratory

estimation of the SGOR showed that at the intermediate equilibrium pressures, the SGORs for the LIndbergh oil were slightly higher than those for the Lloydminster oil.

Another significant difference between these two oils was in their asphaltene content -- the Lindbergh oil contained a much higher percentage of asphaltene than the Lloydminster oil. With these oil characteristics in mind, the oil production rates for these two oils were compared and presented in Figure 30.

Note that for pressure drawdown less than 3 MPa, the Lloydminster oil yielded consistently higher production rate than the Lindbergh oil. This was quite expected because of the fact that the Lloydminster was the lighter oil and with lower asphaltene content. But when the pressure drawdown applied exceeded 3 MPa, both oils essentially yielded same production rate under similar drawdown. Thus, it can be assumed that the Lloydminster oil being the lighter oil had a lesser capability to retain solution gas at a higher drawdown, whereas reverse seemed to be the case for the more viscous Lindbergh oil. Therefore, the advantage that the Lloydminster oil had in terms of its lower viscosity was offset by the slower release of gas from the more viscous Lindbergh oil.

7.0 SUMMARY AND CONCLUSIONS

Presented in the report is an experimental investigation of the flow of foamy oils through porous media using both refined and reservoir oils. Based on the experimental results obtained for the specific rock-fluid systems used in this study, the following conclusions can be drawn.

1. The primary production of heavy oils under solution gas drive is a complex process involving an interplay of several mechanisms including the nucleation, growth and coalescence of gas bubbles, formation of foam and multi-phase fluid flow in porous media.
2. There was no evidence that the presence of nucleated gas bubbles enhanced the mobility of the heavy oil; rather, like in conventional solution-gas-drive reservoirs, the oil mobility decreased due to the gas nucleation.
3. The flow behaviour was significantly affected by the characteristics of the oil being used. However, due to the limited scope of the work, the roles of the viscosity and the asphaltene content of the oil could not be precisely delineated.
4. The trapped gas saturation near the outlet end of the sandpack appeared to be very high.
5. It is likely that the heavy oil/gas mixture flows in the form of an oil continuous foam.

8.0 RECOMMENDATIONS

It is evident from the preceding discussion that the flow of heavy oils through porous media under solution gas drive conditions is highly complex and the mechanisms involved are yet to be fully delineated. Therefore, further studies in the following directions are recommended for developing a better understanding of this process:

1. A systematic evaluation of the role of oil viscosity in the formation of a oil-continuous foam which may be responsible for the high trapped gas saturation.

2. A systematic evaluation of the role of the asphaltene content of the oil.

3. A systematic evaluation of the role of porous medium characteristics.

4. An evaluation of the effects of additives which promote the formation of oil continuous foams.

ACKNOWLEDGEMENTS

Authors wish to thank Roy Woo for his assistance in setting up the data acquisition system and Joseph Najman for the asphaltene analysis.

REFERENCES

Amyx, J.W., Bass, D.M. and Whiting, R.L.: *Petroleum Reservoir Engineering*. McGraw-Hill Book Company, New York (1960), 32-33.

Chatenever, A., Indra, M.K. and Kyte, J.R.: "Microscopic Observations of Solution-Gas Drive Behaviour". Journal of Petroleum Technology (June, 1959), Vol. 11, 13-15.

Dake, L.P.: *Fundamentals of Reservoir Engineering*. Elsevier Scientific Publishing Company, Amsterdam (1978), 80-89.

Danesh, A., Peden J.M., Krinis, D. and Henderson,.D.:"Pore Level Visual Investigation of Oil Recovery by Solution Gas Drive and Gas Injection". SPE Paper 16956, 62nd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, September 27-30, 1987.

Danesh, A., Krinis, D. and Henderson,.D., and Peden, J.M.:"Pore Level Visual Investigation of Miscible and Immiscible Displacements", Journal of Petroleum Science & Engineering, Vol. 2 (1989), 167-177.

Forest, T.W.: "The Stability of Gaseous Nuclei at Liquid-Solid Interfaces", Journal of Applied Physics (September, 1982), Vol. 53, No. 9, 6191-6201.

Hunt, E.B, Jr., Berry, V.J., Jr.: "Evolution of Gas from Liquids Flowing through Porous Media", A.I.Ch.E. Journal (December, 1956), Vol. 2, No. 4, 560-567.

Khatib, Z.I., Hirasaki, G.J. and Falls, A.H.: "Effects of Capillary Pressure on Coalescence and Phase Mobilities in Foams Flowing Through Porous Media". SPE Paper 15442, 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, October 5-8, 1986.

Leontaritis, K.J. and Mansoori, G.A.: "Asphaltene Flocculation during Oil Production and Processing: A Thermodynamic Colloidal Model", SPE 16258, Society of Petroleum Engineers International Symposium on Oilfield Chemistry (1987).

Plesset, M.S. and Prosperetti, A.: "Bubble Dynamics and Cavitation". Annual Review of Fluid Mechanics (1977), No. 9, 145-185.

Smith, G.E.: "Fluid Flow and Sand Production in Heavy Oil Reservoirs Under Solution Gas Drive". SPE Paper 15094, 56th California Regional Meeting of the Society of Petroleum Engineers, Oakland, April 2-4, 1986.

Stewart, C.R., Hunt, E.B., Schneider, F.N., Geffen, T.M. and Berry, V.J.,Jr.: "The Role of Bubble Formation in Oil Recovery by Solution Gas Drives in Limestones". Trans. AIME (1954), Vol. 201, 294-301.

Ward, C.A. and Levart, E.: "Conditions for Stability of Bubble Nuclei in Solid Surfaces Contacting a Liquid-Gas Solution". Journal of Applied Physics (1984), Vol.56, No.2.

Ward, C.A., Tikuisis, P. and Venter, R.D.: "Stability of Bubbles in a Closed Volume of Liquid-Gas Solution". Journal of Applied Physics (1982), Vol. 53, No. 9

Yen, T.F.: "Present Status of the Structure of Petroleum Heavy Ends and Its Significance to Various Technical Applications", Preprints of American Chemical Society - Division of Petroleum Chemistry (1972), F102-114.

Yortos, Y.C. and Parlar, M.: "Phase Change in Binary Systems in Porous Media: Application to Solution-Gas Drive". SPE Paper 19697, 64th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, San Antonio, October 7-11, 1989.

Table 1: Properties of Porous Media

Parameters	Glass Beads	Silica Sand
Length (m)	2.0	2.0
Cross-Sectional Area (m^2)	16.1E-4	16.1E-4
Mesh Size	140	140-200
Porosity (fraction)	0.357	0.33
Permeability (darcy)	18.4	3.35
Oils Used	Bright-150 Lloydminster	Lloydminster Lindbergh

Table 2: Properties Reservoir Oil Samples

Oil	Company	API Gravity	Asphaltene (wt %)	Viscosity @20°C (mPa.s)
Bright-150	Sunoco, NY	27.5	-	2076.7
Lloydminster	Mobil	12.6	14.11	8580.0
Lindbergh	PanCanadian	11.0	20.67	10500.0

Table 3: Live Oil Conditions at 21°C

Oil	Density (kg/m^3)	Estimated Viscosity (mPa.s)	Initial Soln. Gas-Oil-Ratio (m3/m3)	End-Point Sg (%)
Bright-150	890.5	860.7	N/A	N/A
Lloydminster	968.0	3007.5	14.8	13.8
Lindbergh	978.0	3970.2	13.6* 14.7**	11.9* 17.58**

* At horizontal position

** At vertical position

Figure 1: Schematic Diagram of the Experimental Apparatus

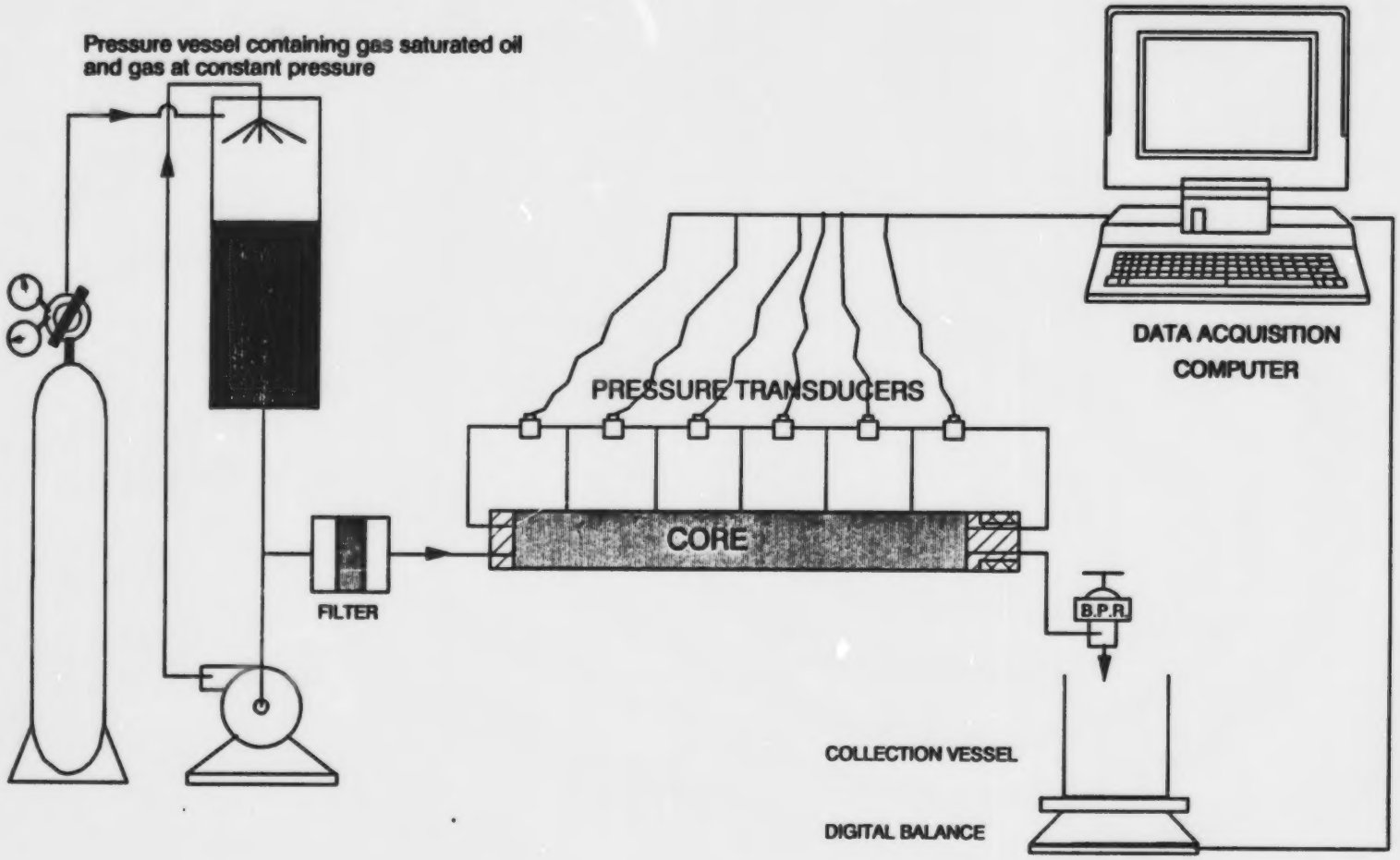

Figure 2: Oil-Gas Recombination Equipment

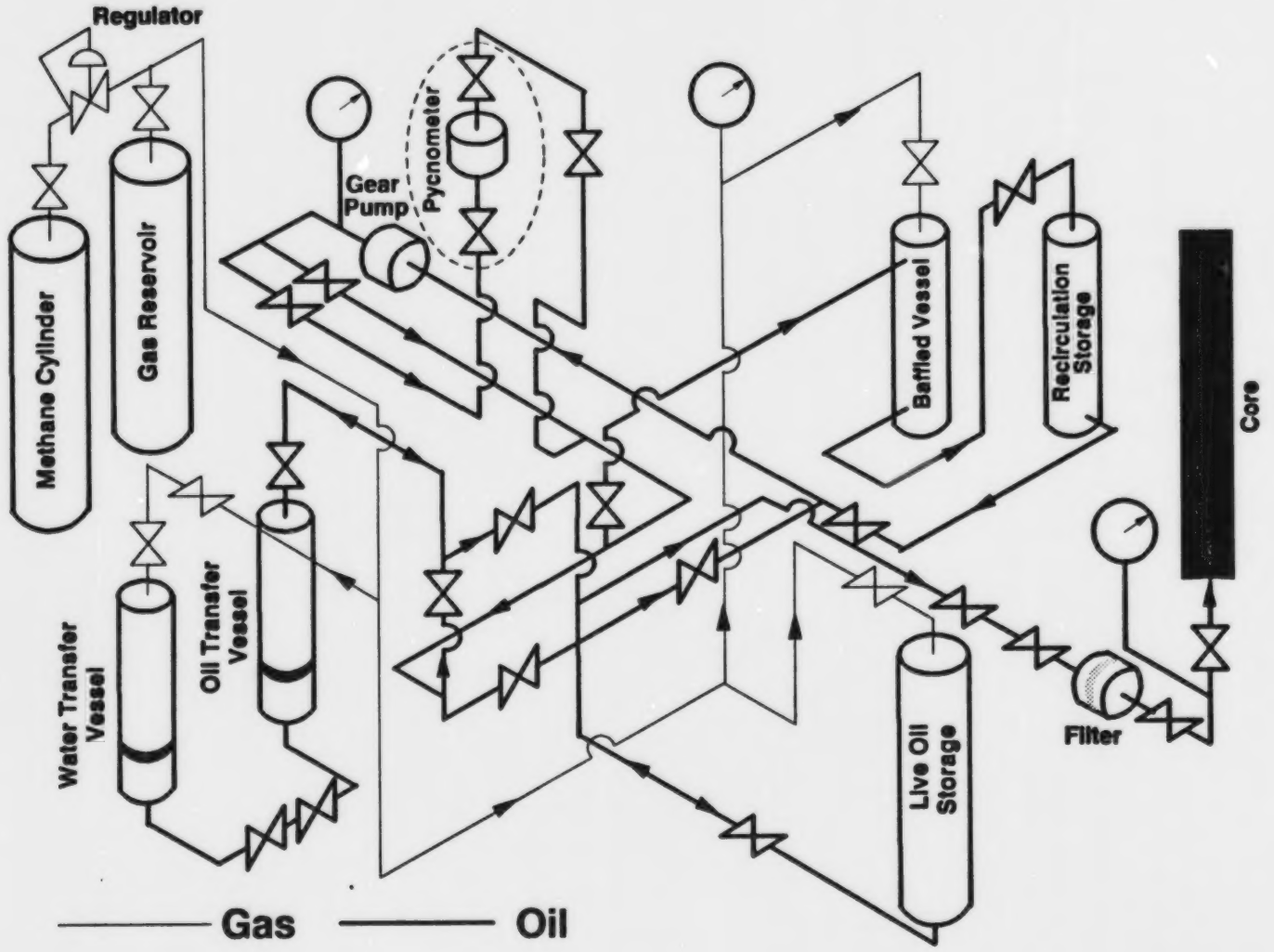

Figure 3: Solution Gas-Oil-Ratio As A Function of the Equilibrium Pressure as Measured in a Differential Liberation Test

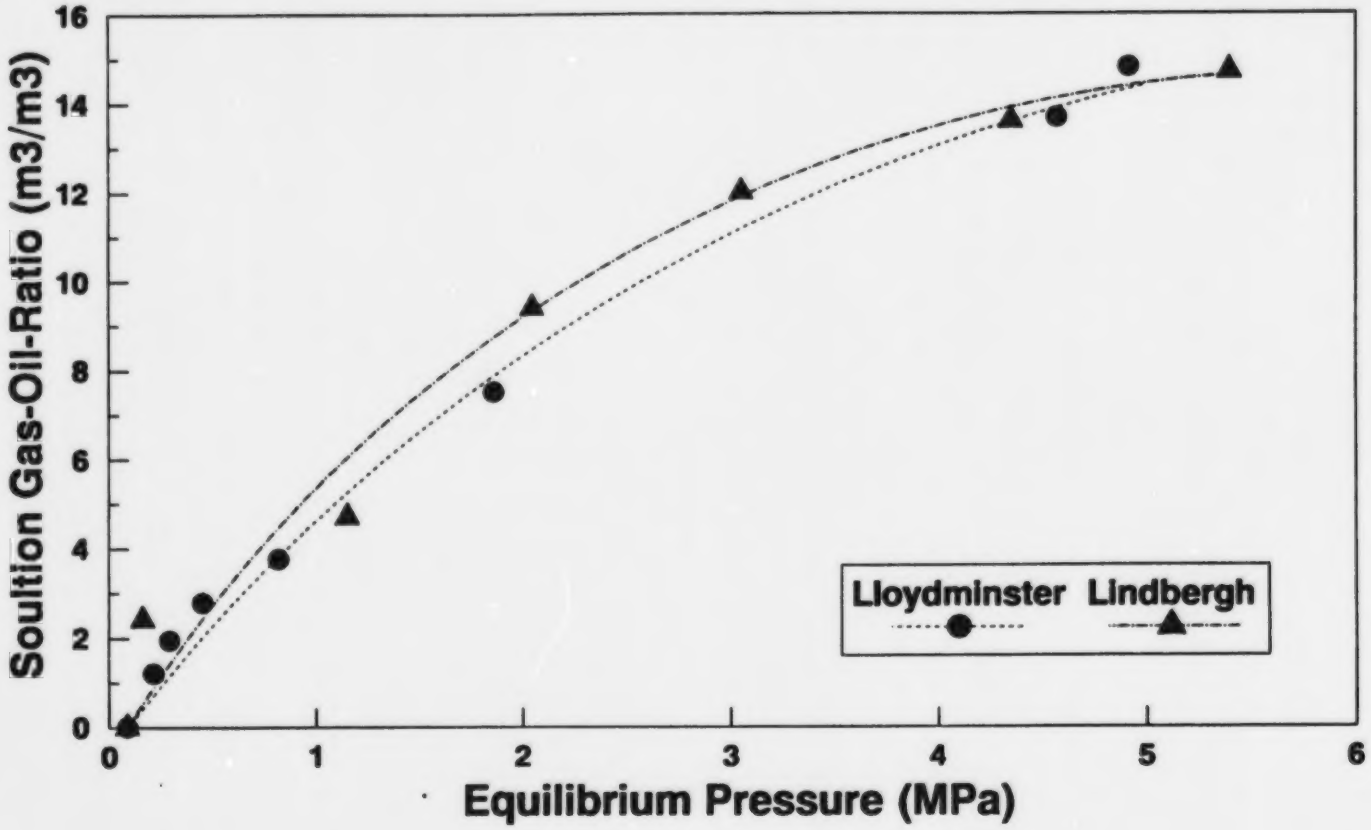

Figure 4: Homogeneity Test of Porous Medium (Oil Used: Refined Bright-150 Oil)

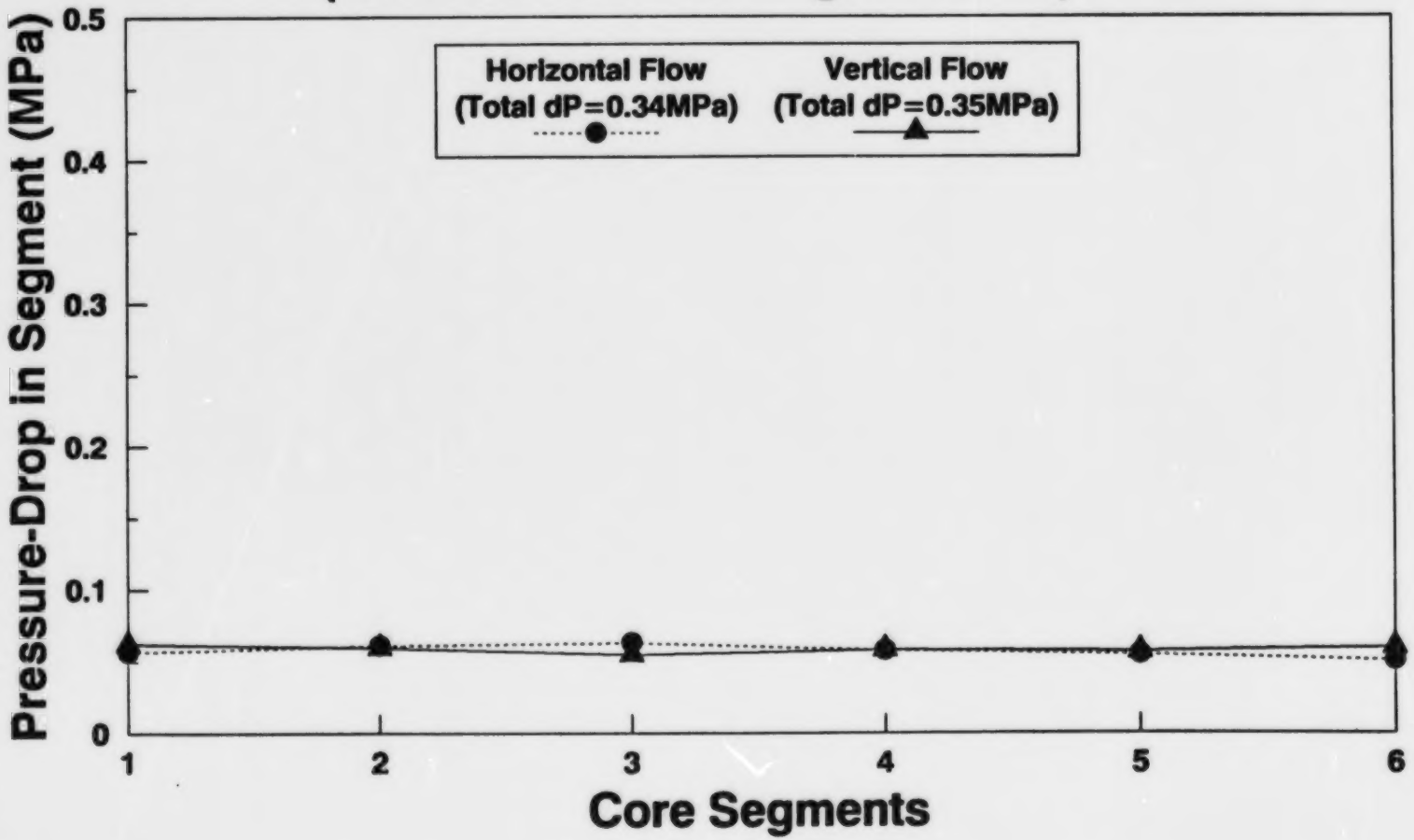

Figure 5: Effect of Pressure Drawdown on the Oil Production Rate for Gas-Saturated Refined Bright-150 Oil

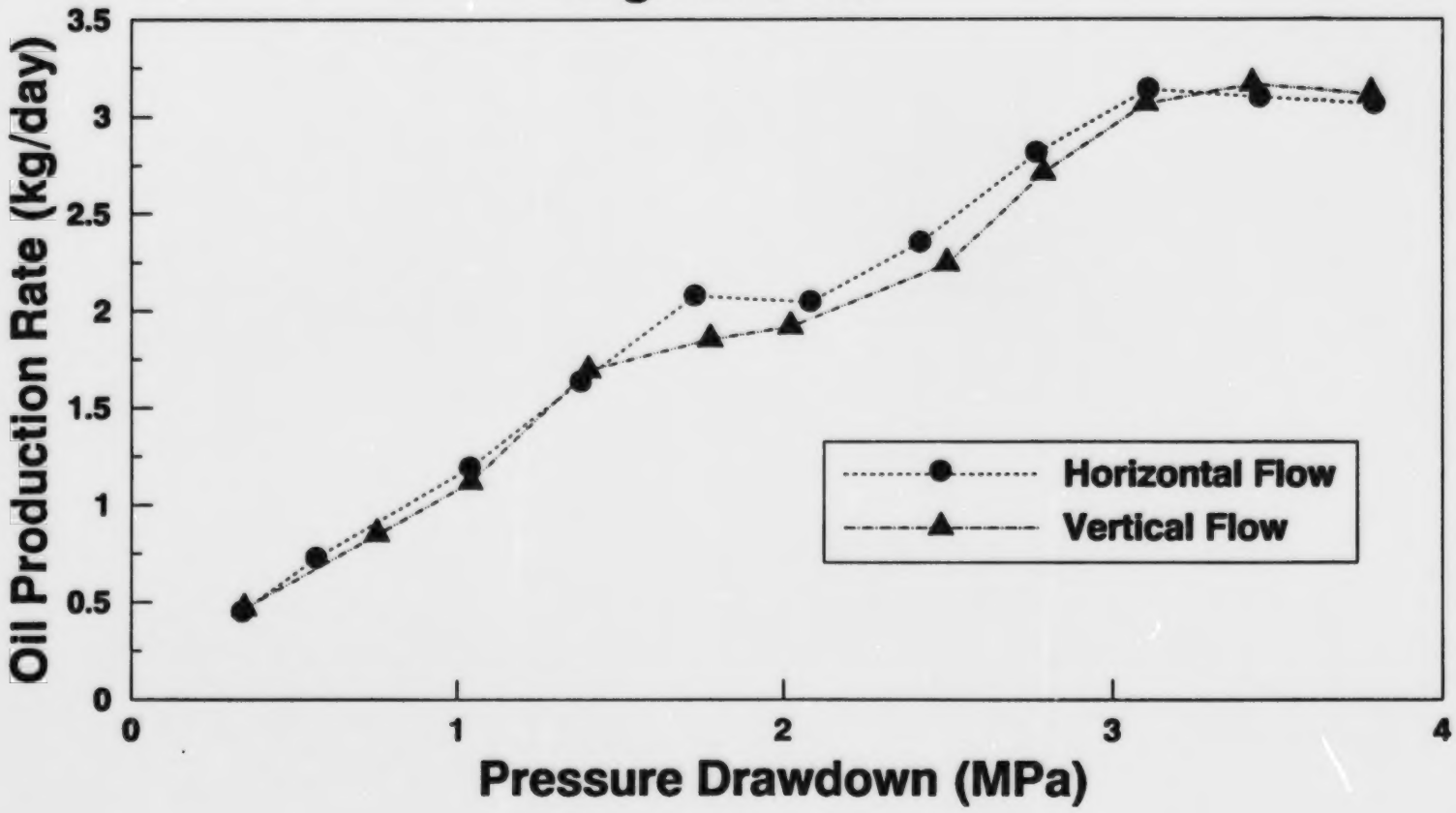

Figure 6: Effect of Pressure Drawdown on the OilProduction Rate for Gas-Saturated Lloydminster Heavy Oil

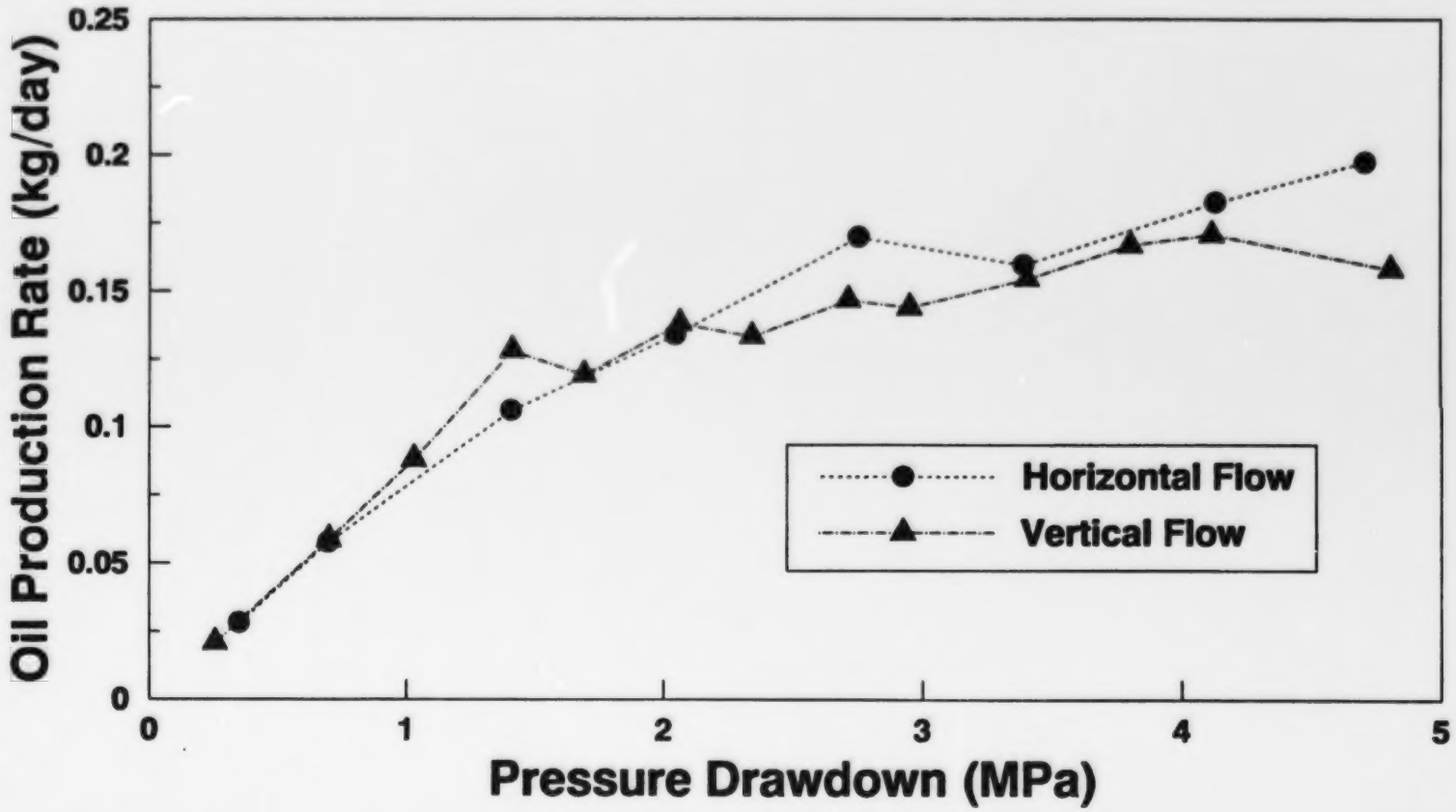

Figure 7: Effect of Pressure Drawdown on The Oil Production Rate for Gas-Saturated Lindbergh Heavy Oil

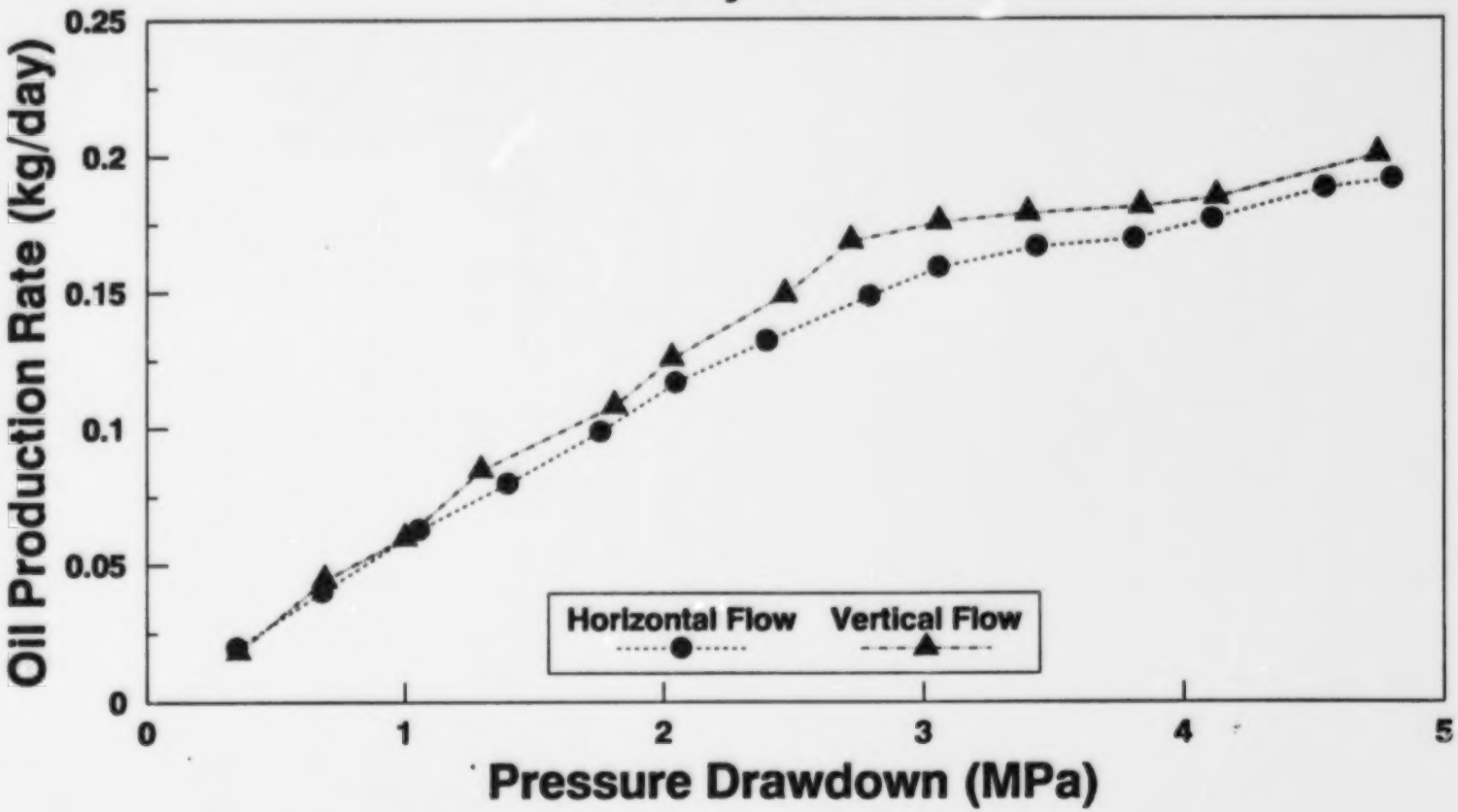

Figure 8: Pressure Distribution in the Porous Medium (Bright-150 Oil; Horizontal Flow)

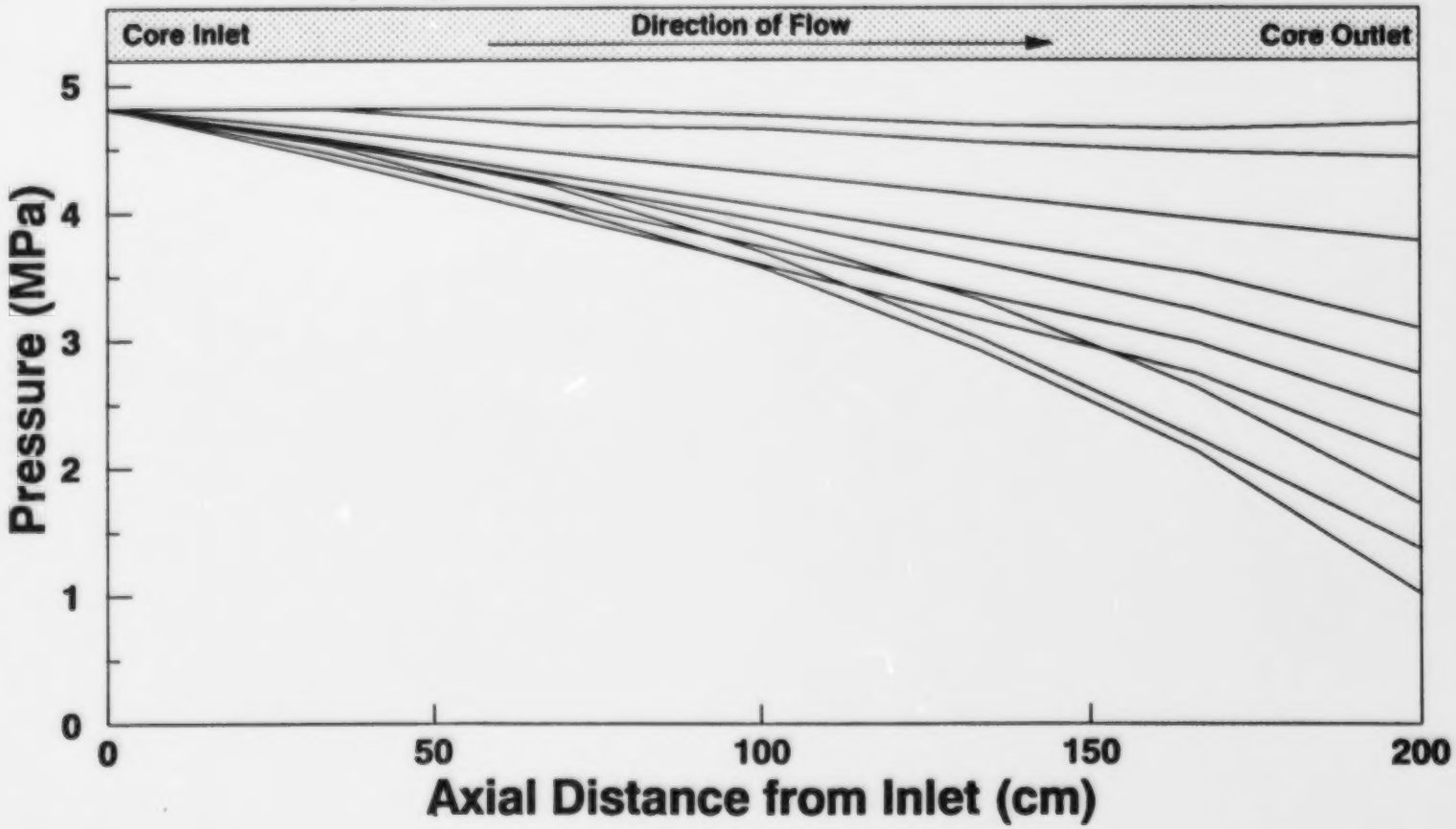

Figure 9: Pressure Distribution in the Porous Medium (Bright-150 Oil; Vertical Flow)

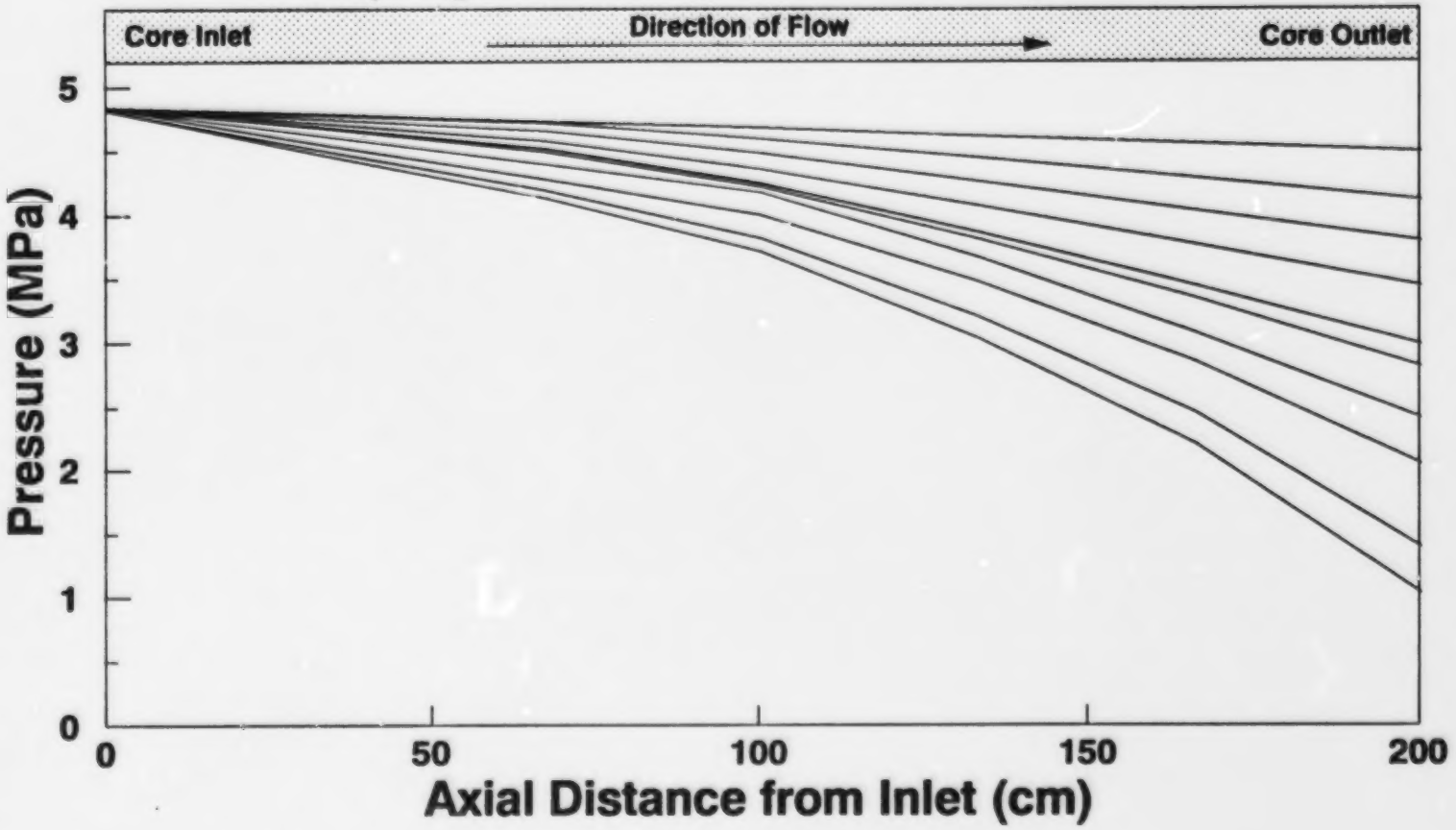

Figure 10: Pressure Distribution in the Porous Medium (Lloydminster Heavy Oil; Horizontal Flow)

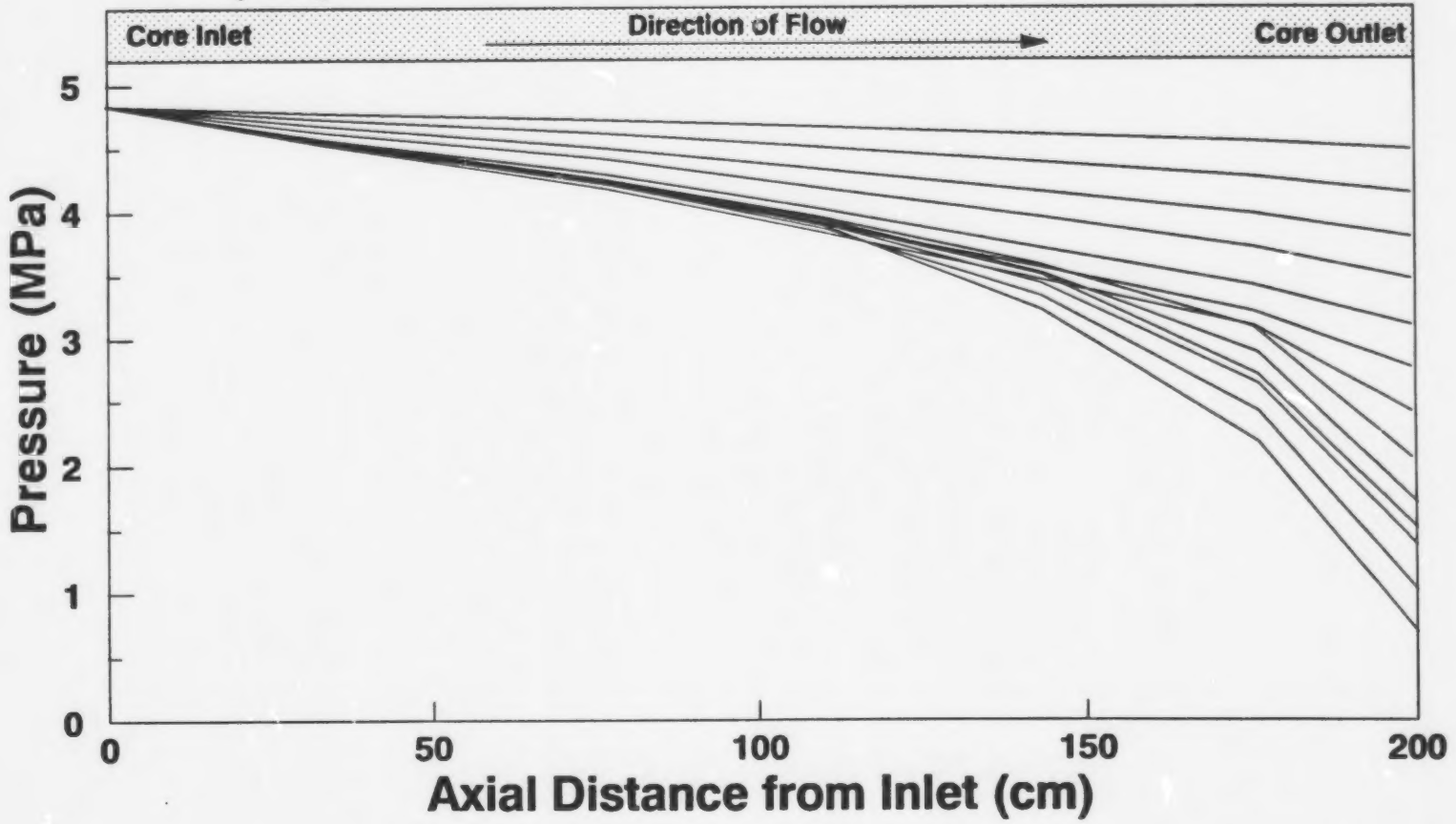

Figure 11: Pressure Distribution in the Porous Medium (Lloydminster Heavy Oil; Vertical Flow)

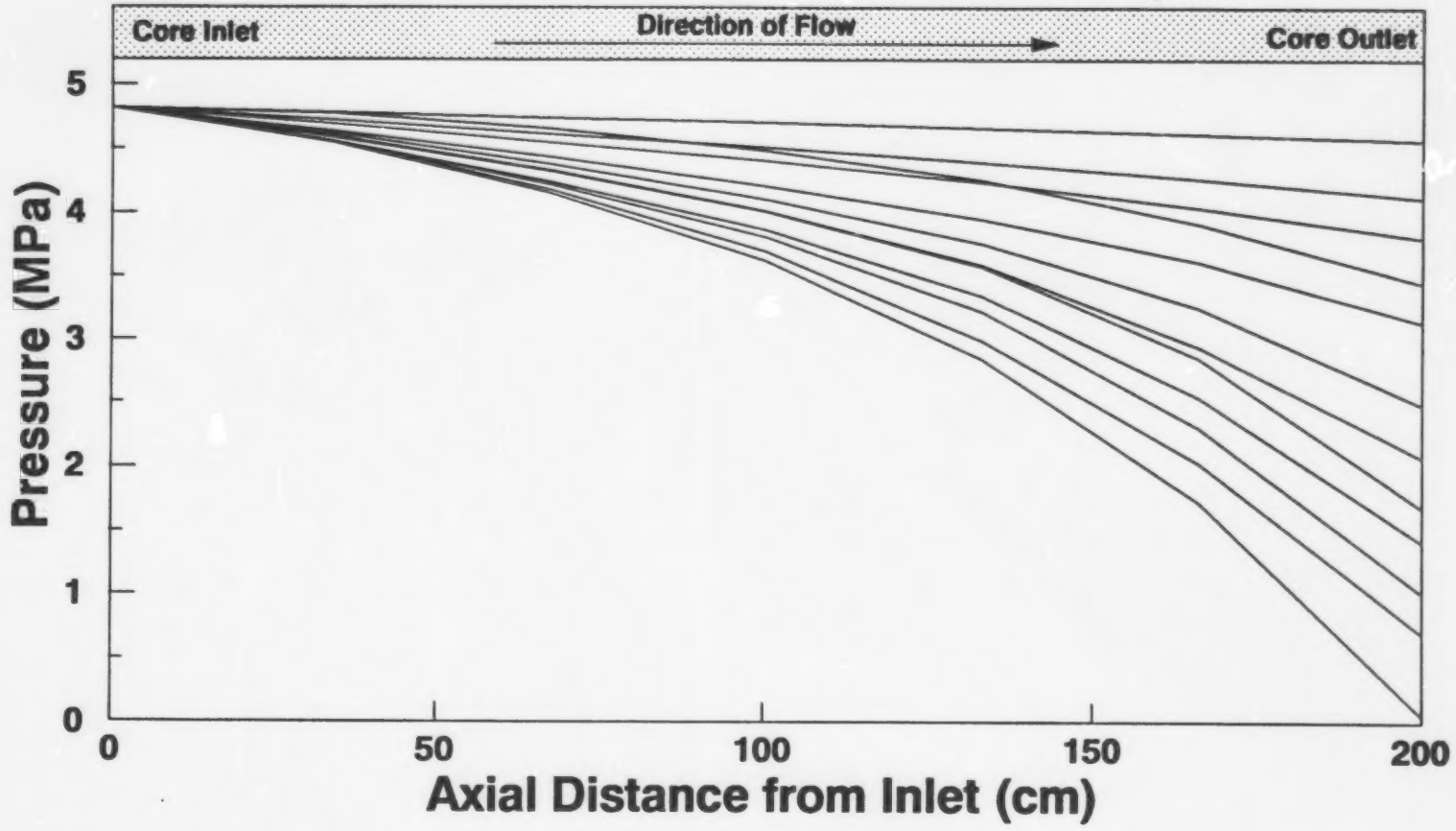

Figure 12: Pressure Distribution in the Porous Medium (Lindbergh Heavy Oil; Horizontal Flow)

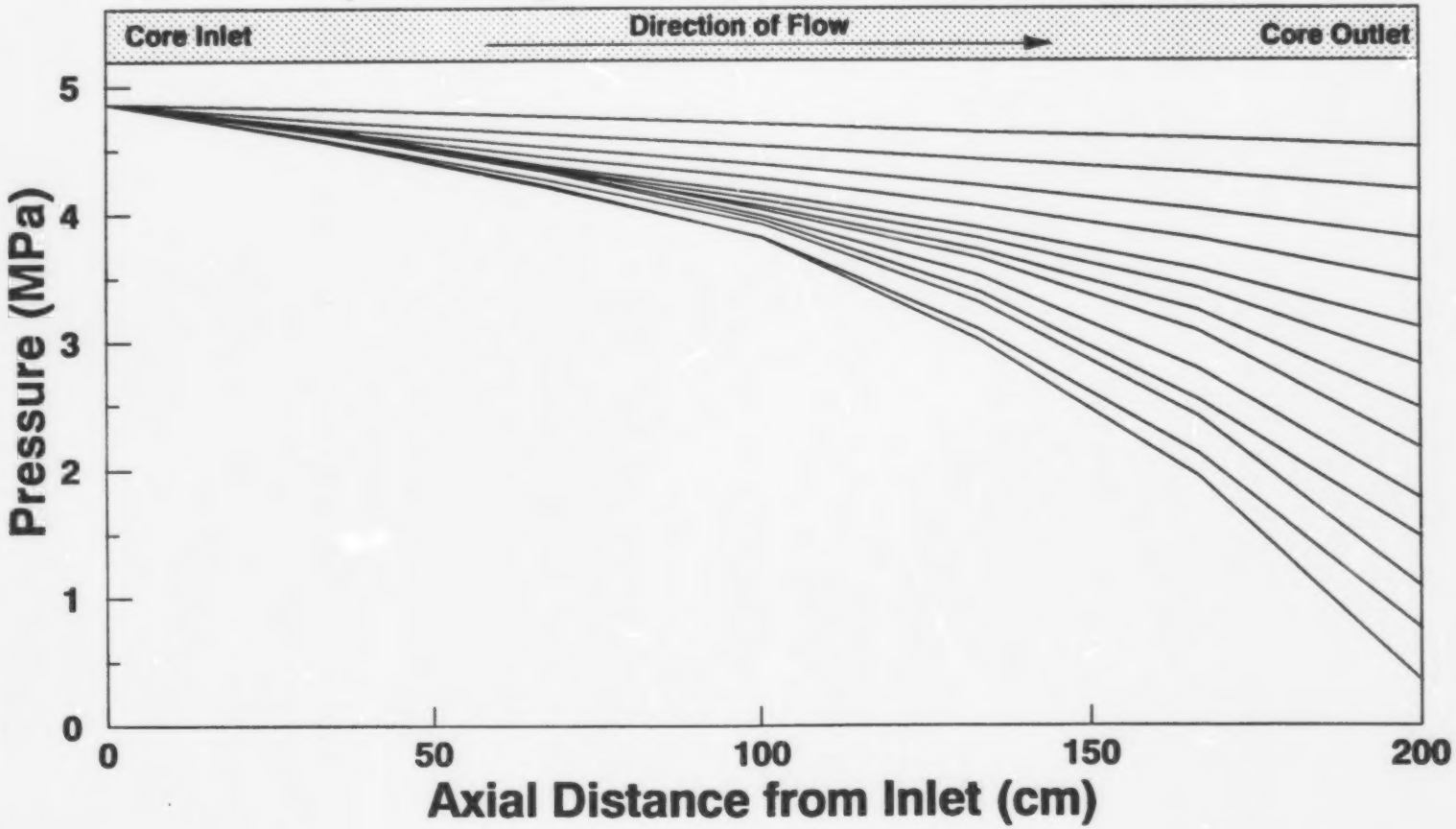

Figure 13: Pressure Distribution in the Porous Medium (Lindbergh Heavy Oil; Vertical Flow)

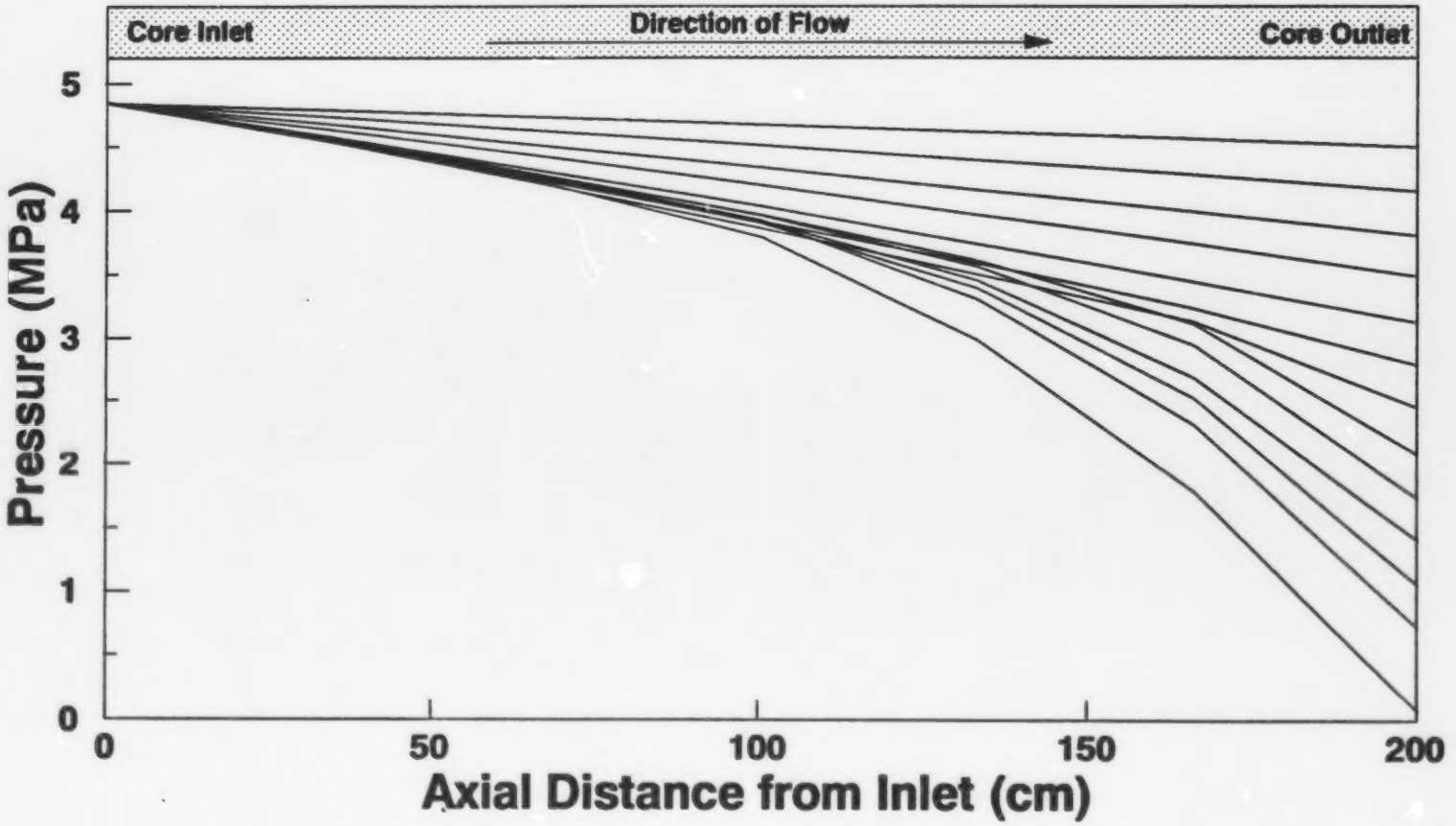

Figure 14: Comparison of Vertical and Horizontal Pressure Distributions for Bright-150 Oil

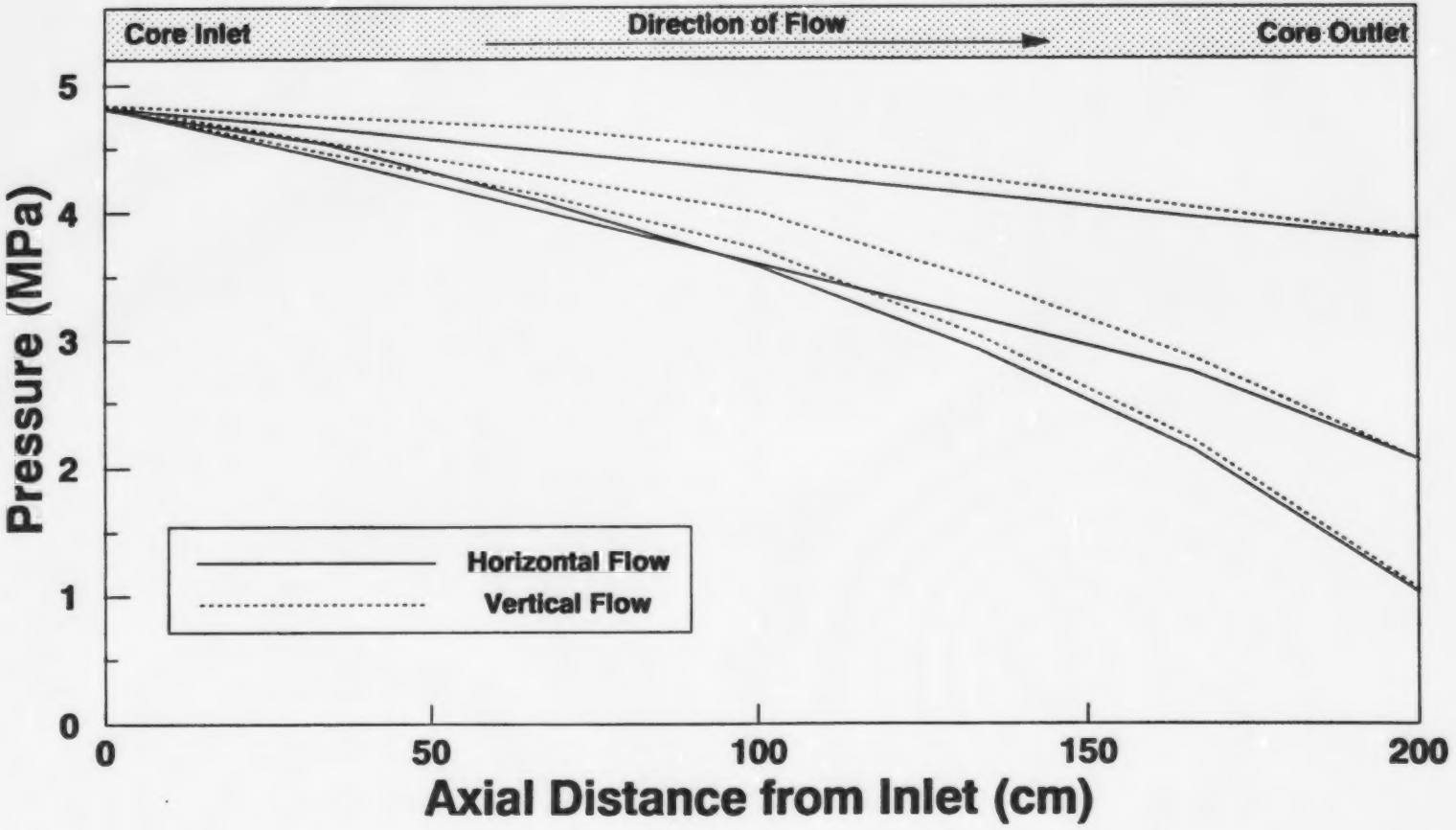

Figure 15: Comparison of Vertical and Horizontal Pressure Distributions for Lloydminster Heavy Oil

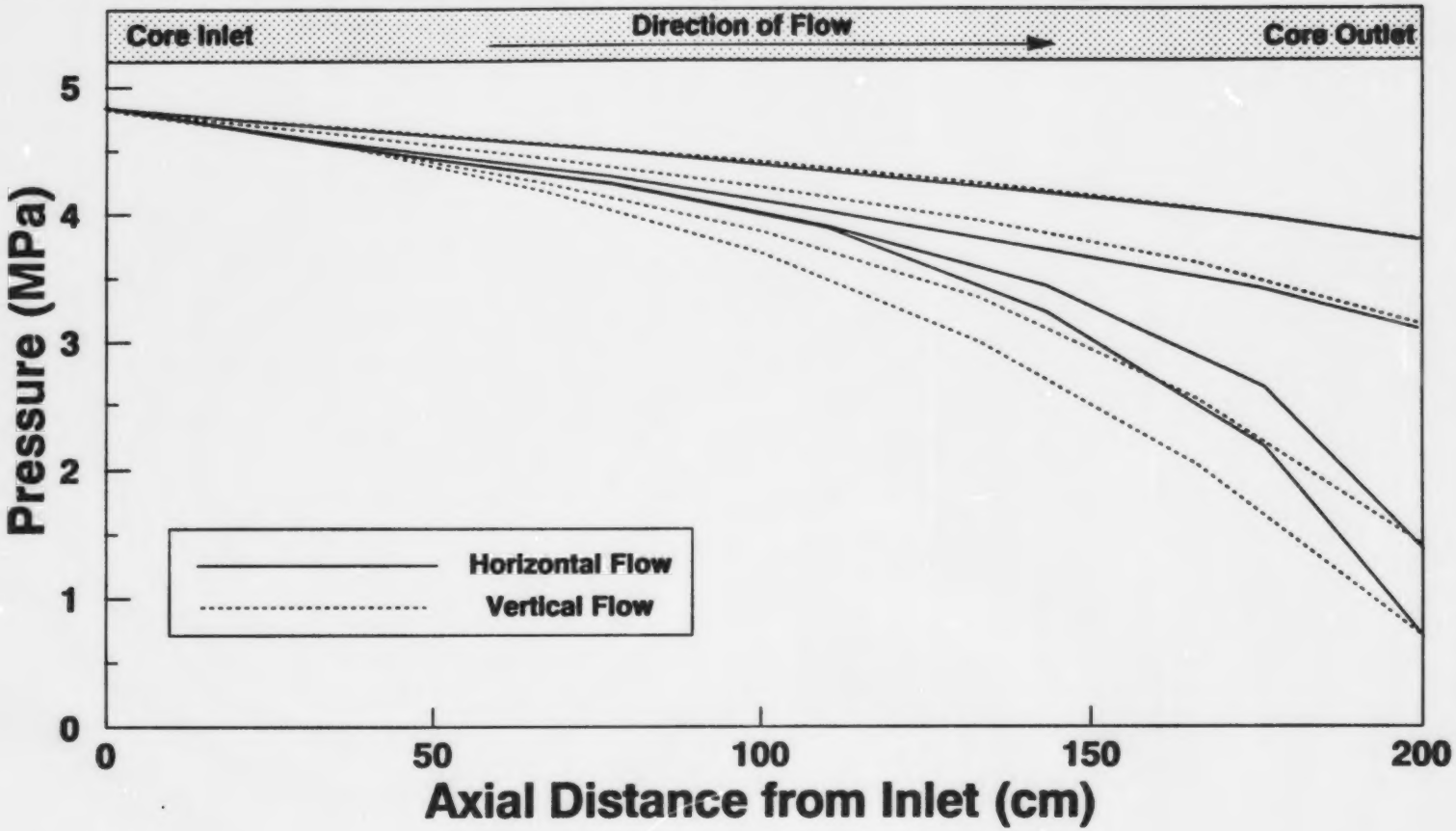

Figure 16: Comparison of Vertical and Horizontal Pressure Distributions for Lindbergh Heavy Oil

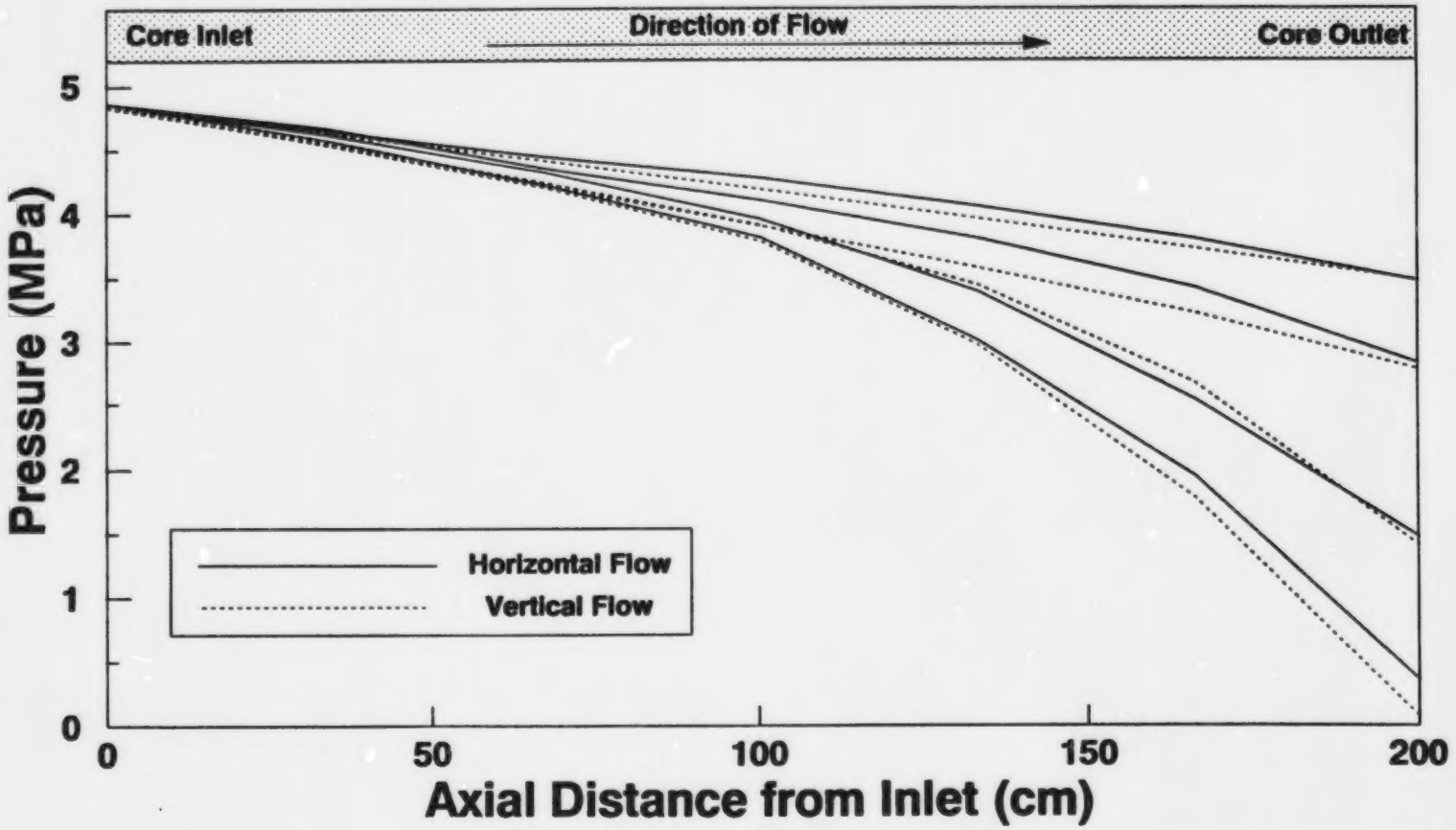

Figure 17: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Bright-150 Oil; Horizontal Flow; Total Drawdown Pressure: 1.0 MPa)

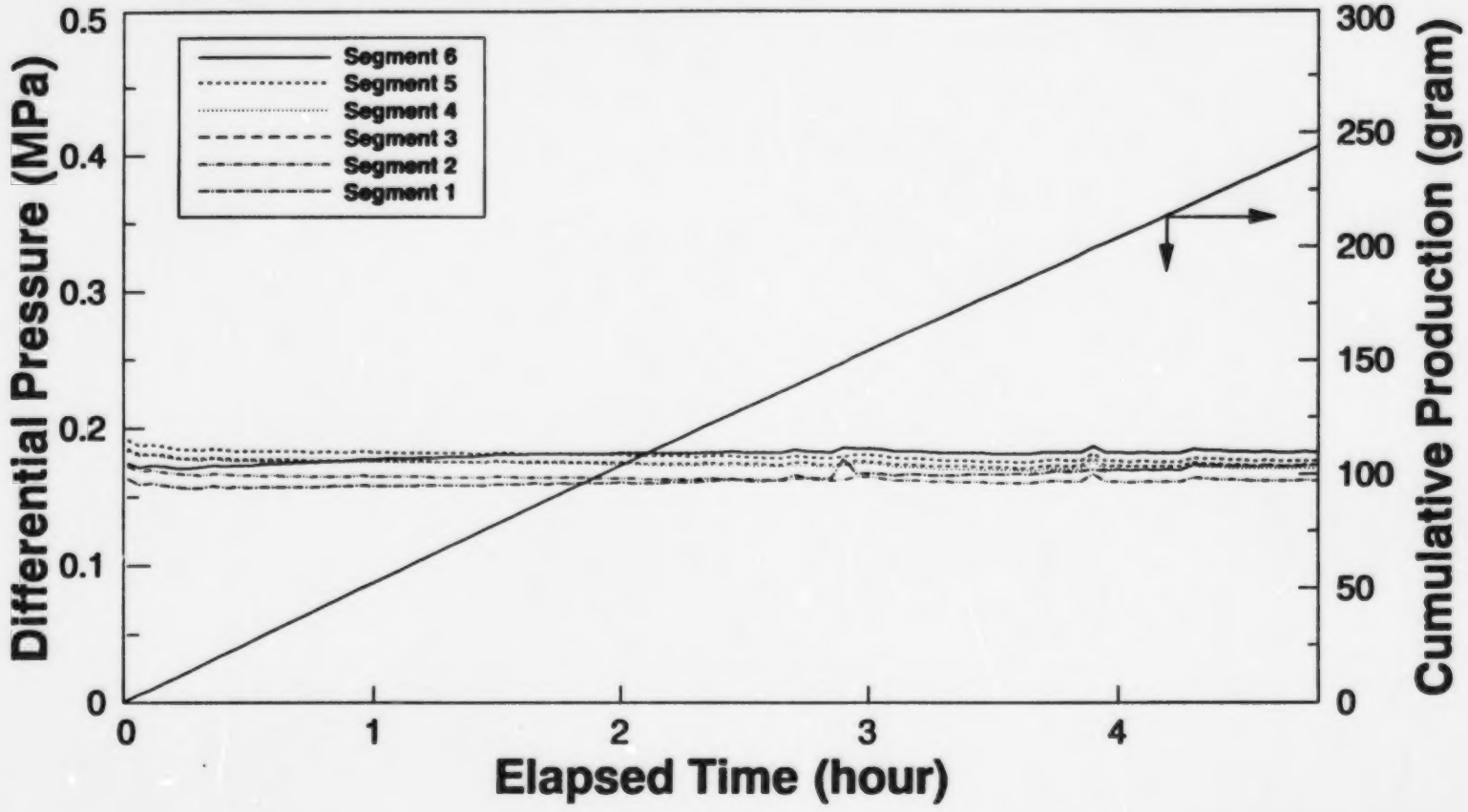

Figure 18: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Bright-150 Oil; Horizontal Flow; Total Drawdown Pressure: 3.4 MPa)

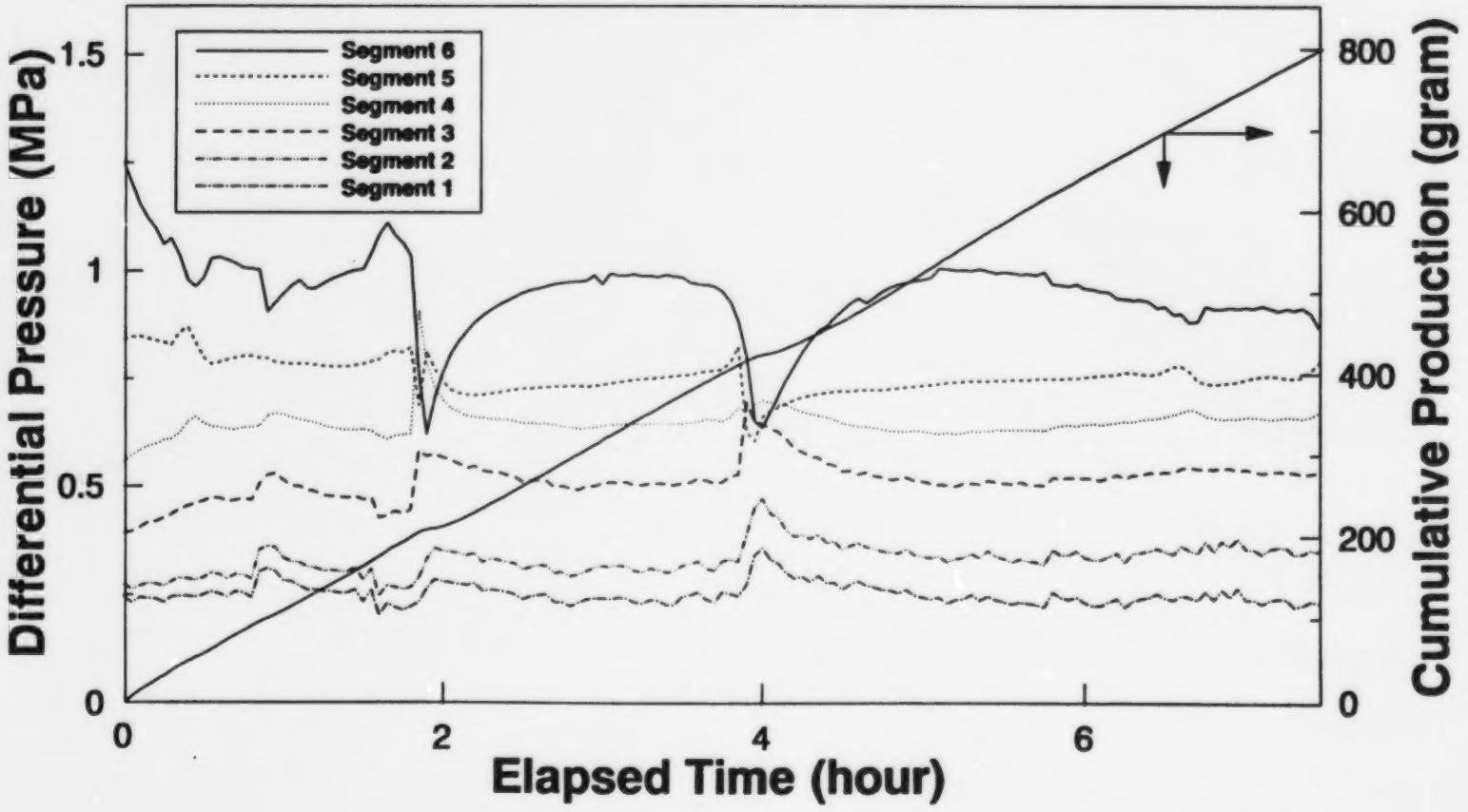

Figure 19: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Bright-150 Oil; Vertical Total Drawdown Pressure: 0.35 MPa)

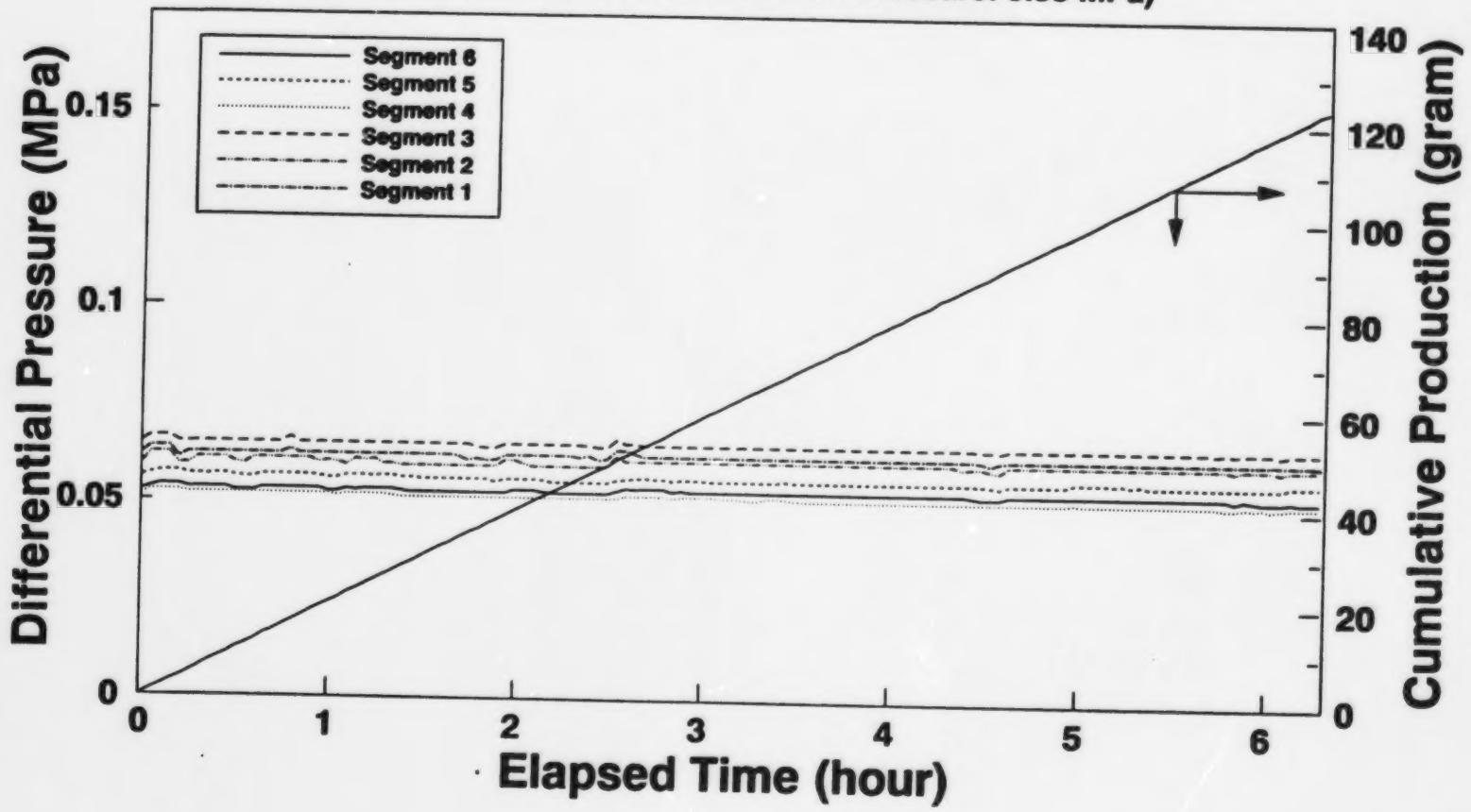

Figure 20: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Bright-150 Oil; Vertical Flow; Total Drawdown Pressure: 3.8 MPa)

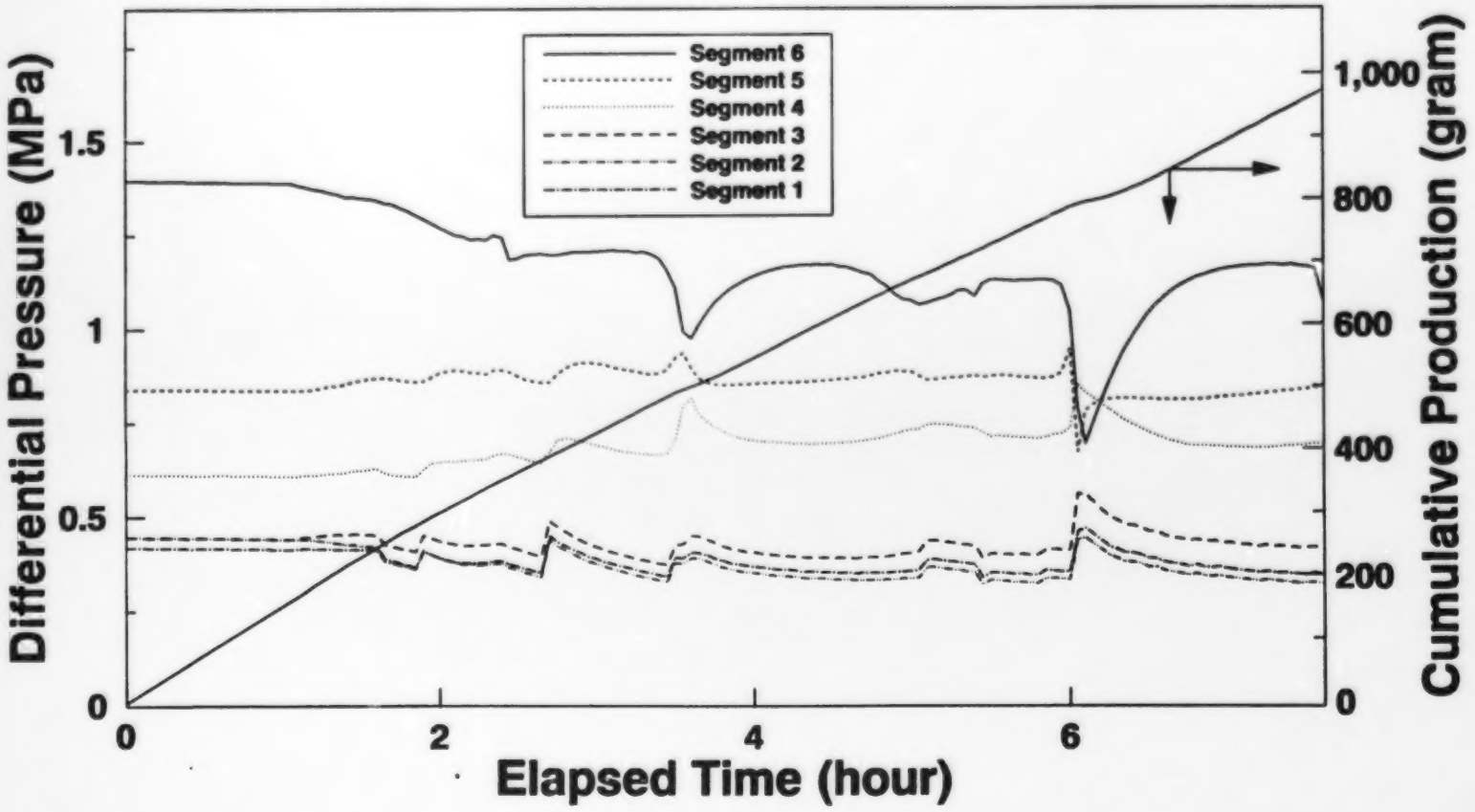

Figure 21: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lloydminster Oil; Horizontal Flow; Total Drawdown Pressure: 0.7 MPa)

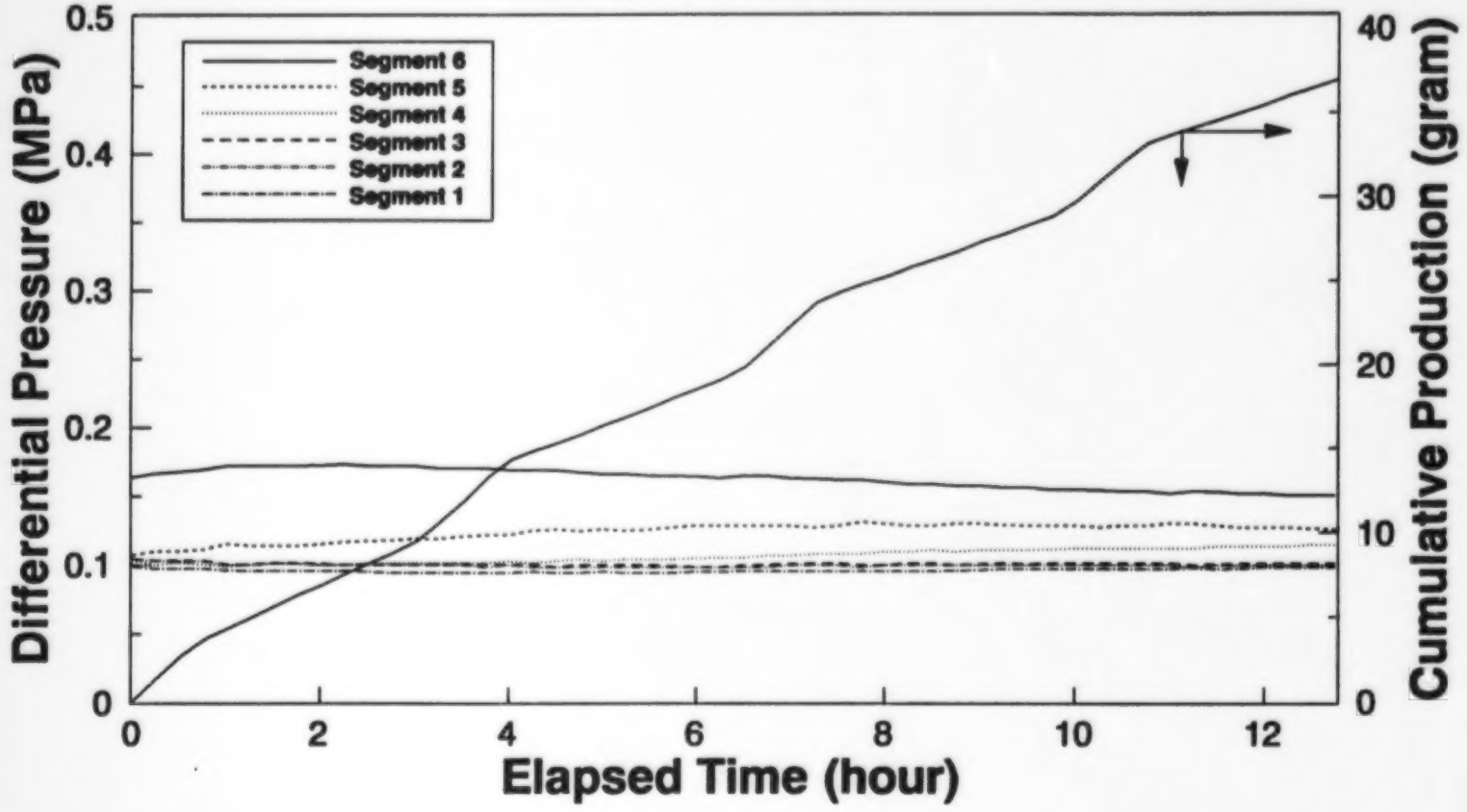

Figure 22: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lloydminster Oil; Horizontal Flow; Total Drawdown Pressure: 4.8 MPa)

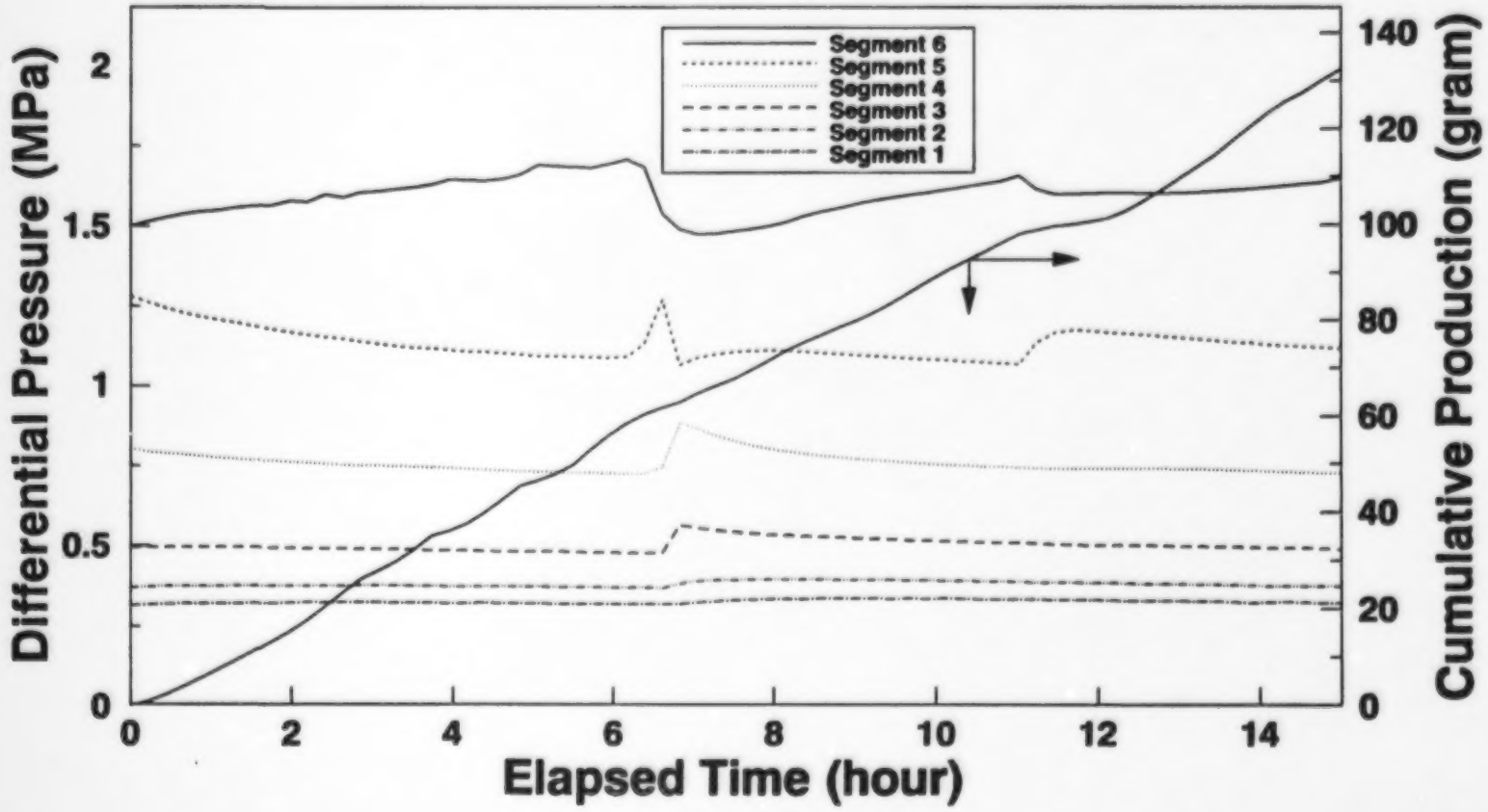

Figure 23: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lloydminster Oil; Vertical Flow; Total Drawdown Pressure: 0.7 MPa)

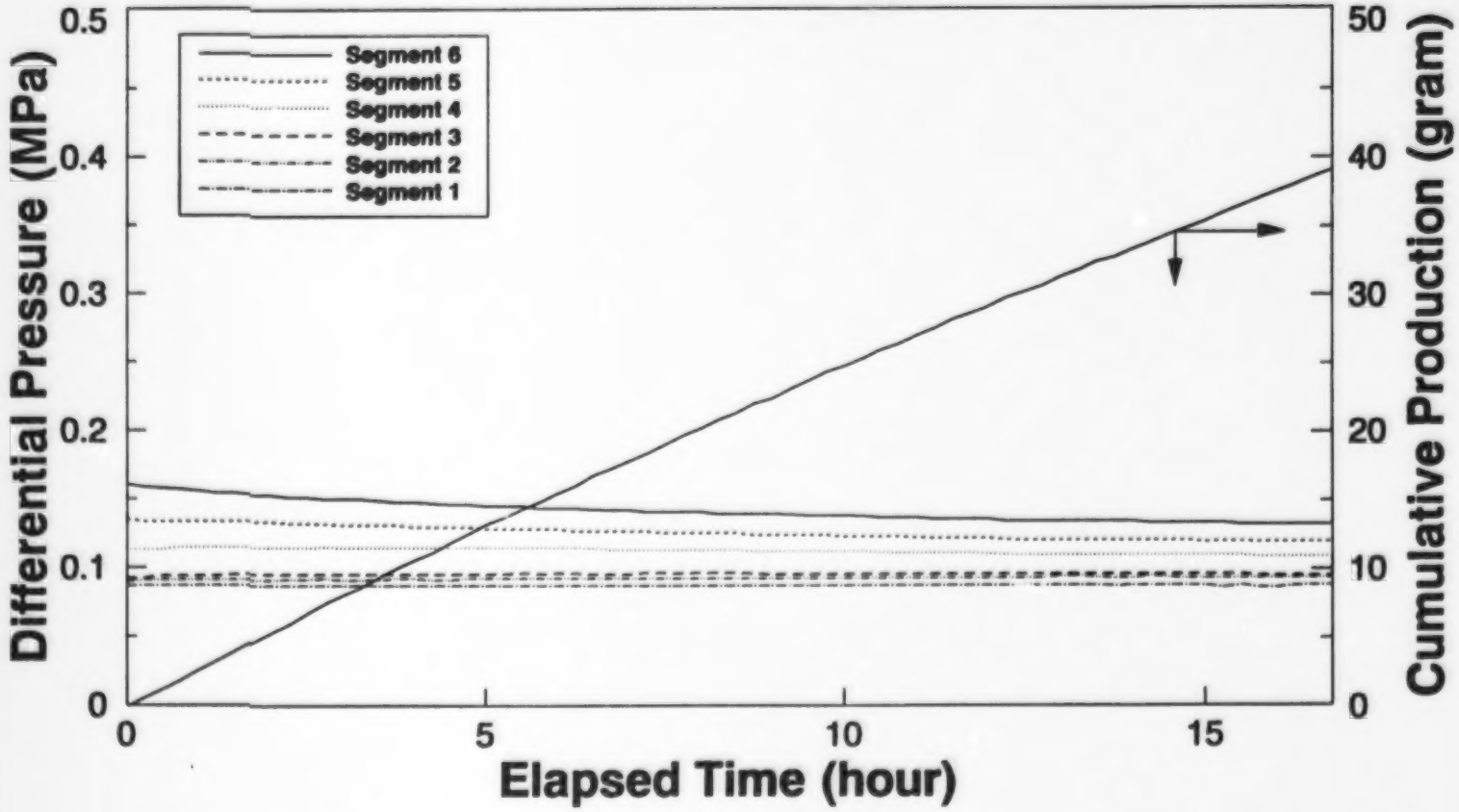

Figure 24: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lloyminster Oil; Vertical Flow; Total Drawdown Pressure: 4.2 MPa)

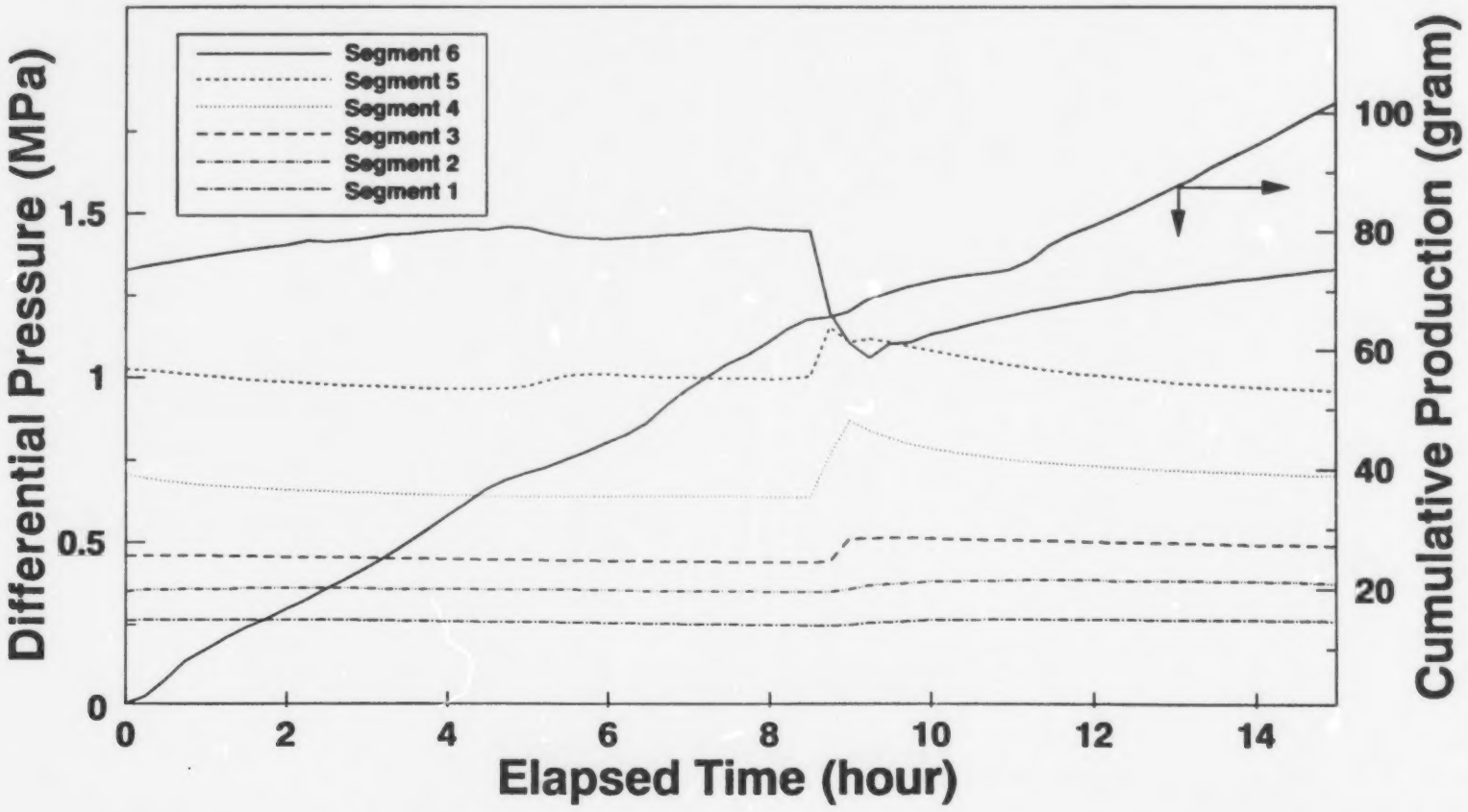

Figure 25: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lindbergh Oil; Horizontal Flow; Total Drawdown Pressure: 1.0 MPa)

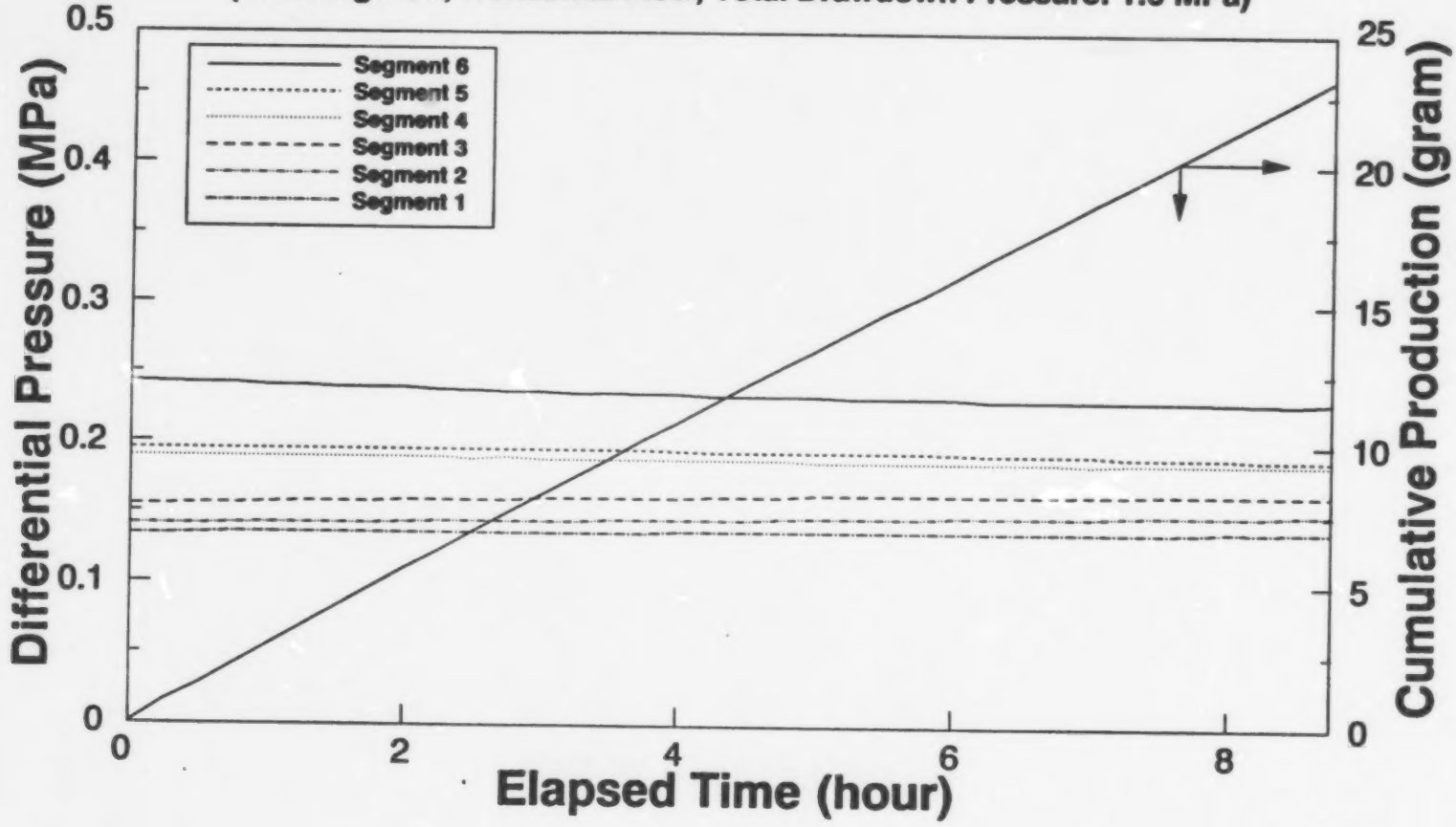

Figure 26: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lindbergh Oil; Horizontal Flow; Total Drawdown Pressure: 3.4 MPa)

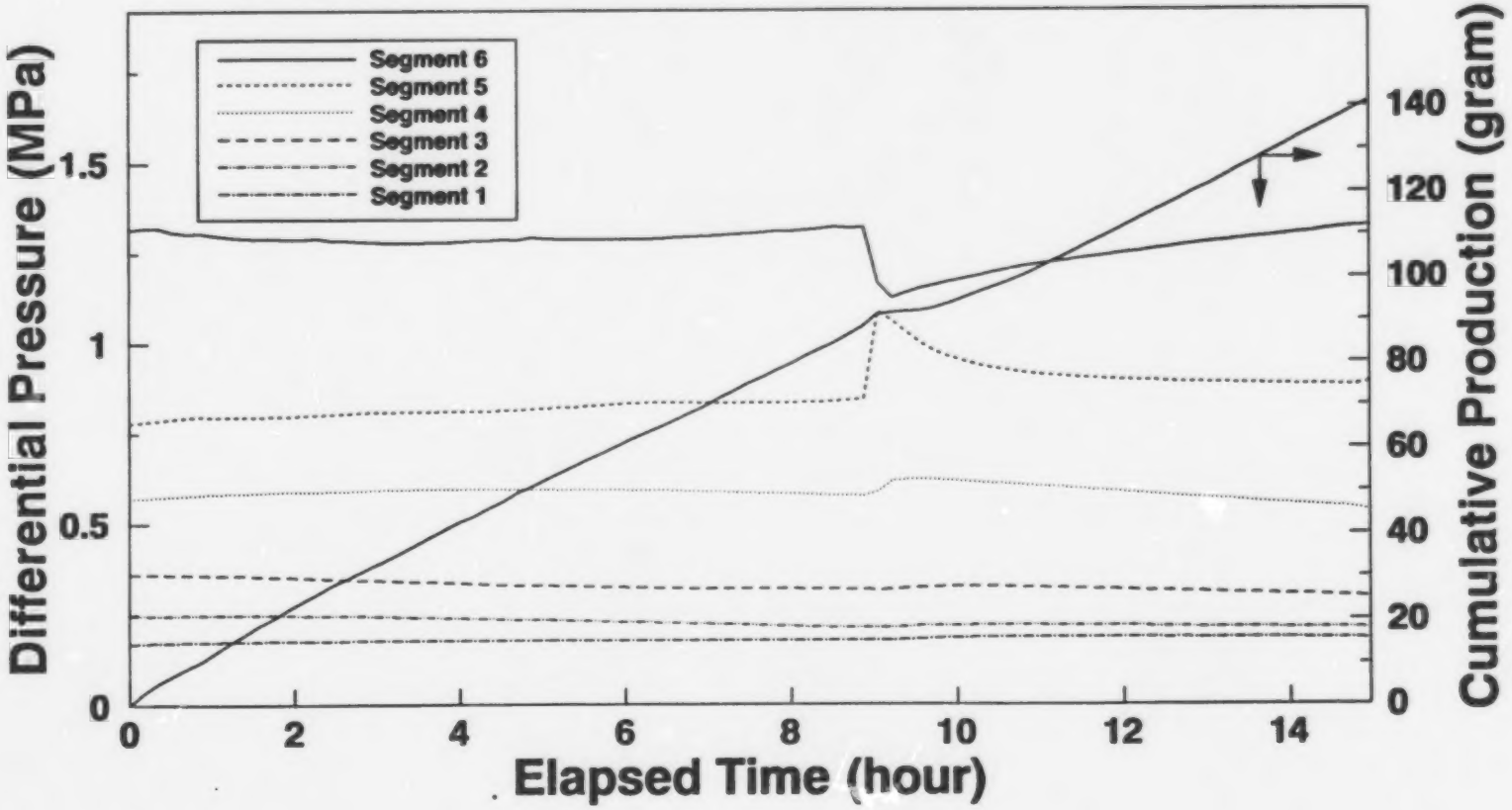

Figure 27: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lindbergh Oil; Vertical Flow; Total Drawdown Pressure: 0.3 MPa)

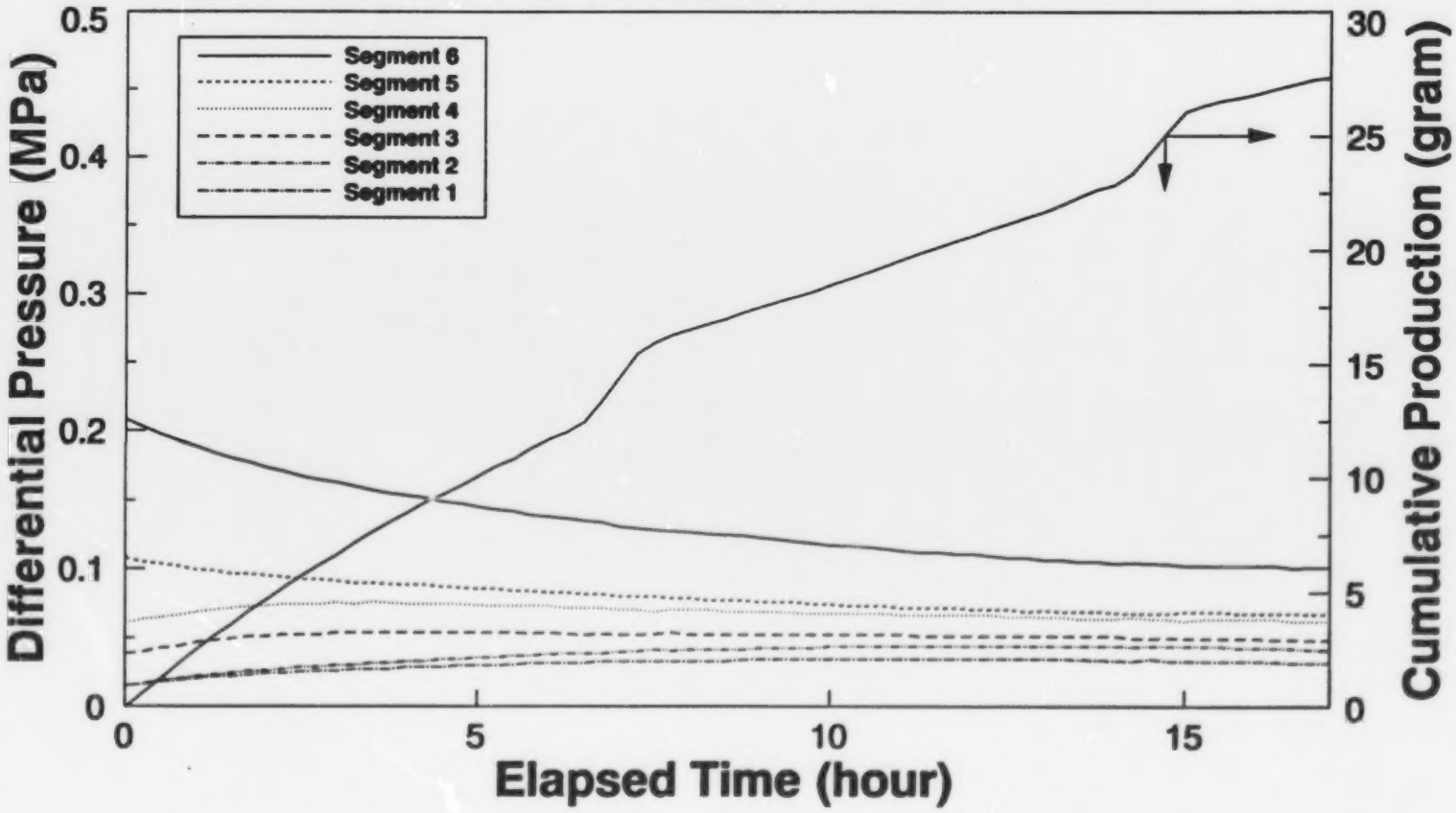

Figure 28: Segmental Pressure Drop and Cumulative Oil Production as Functions of Time

(Lindbergh Oil; Vertical Flow; Total Drawdown Pressure: 4.8 MPa)

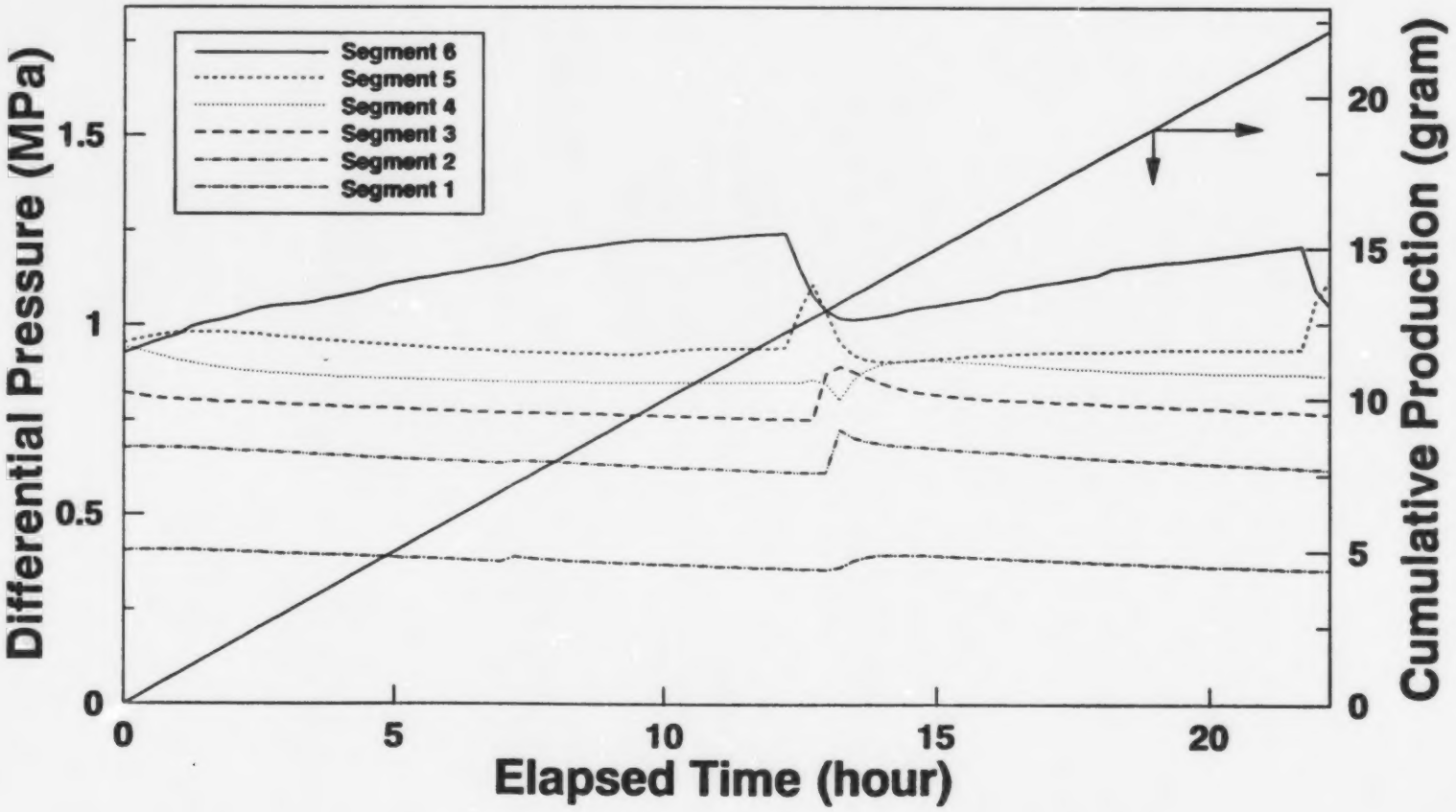

Figure 29: Effect of the Type of Rock Matrix on The Oil Production Rate (Gas-Saturated Lloydminster Heavy Oil; Horizontal Flow)

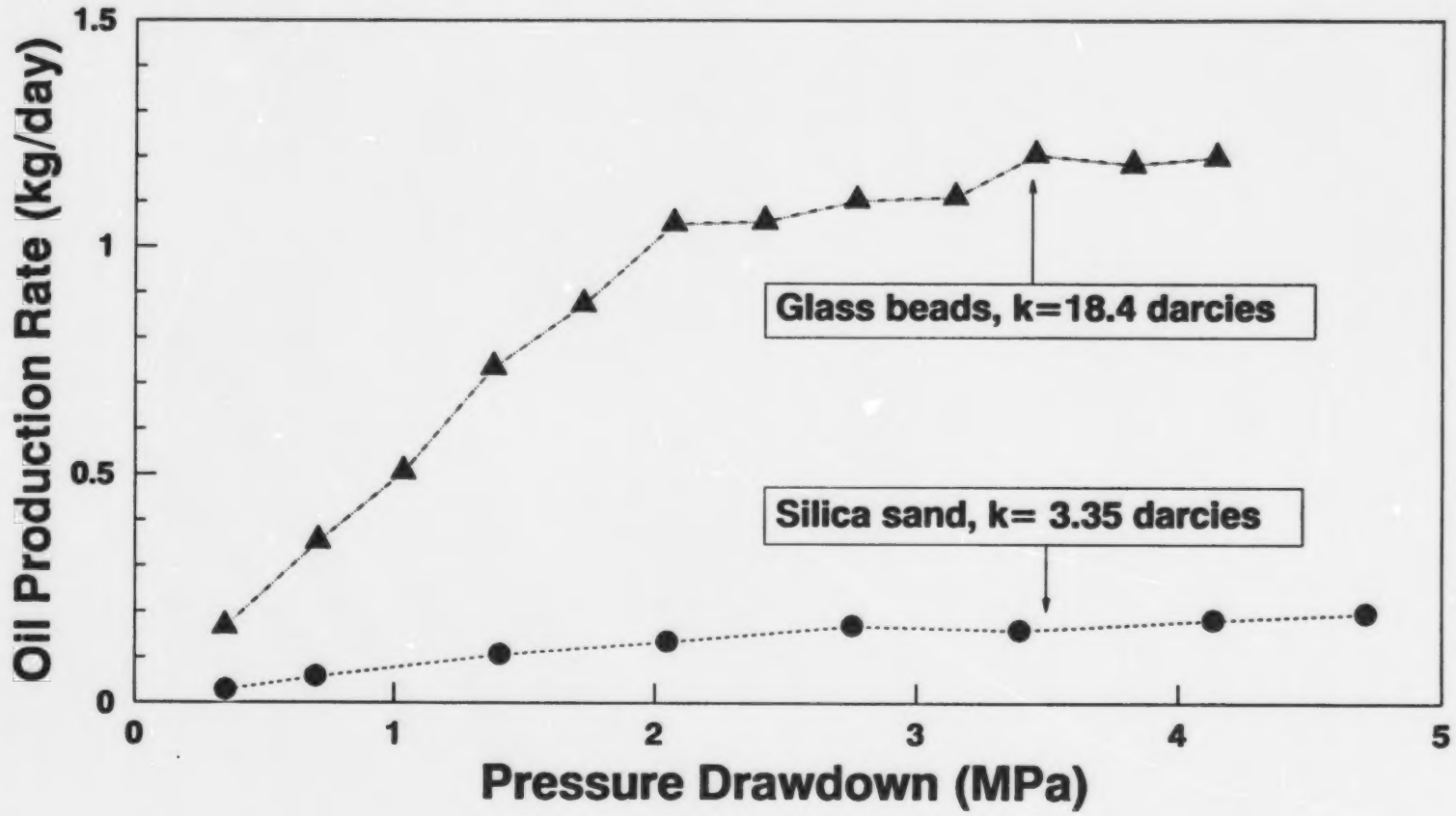

Figure 30: Effect of Oil Characteristics on the Oil Production Rate (Horizontal Flow)